Exhibit A

Examples of Reportable Balancing Contingency Events

Examples of Reportable Balancing Contingency Events

The proposed definition for Reportable Balancing Contingency Event ("RCBE") is

> "Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.
> - Eastern Interconnection – 900 MW
> - Western Interconnection – 500 MW
> - ERCOT – 800 MW
> - Quebec – 500 MW"

Given this proposed definition, the following table shows examples of unit losses and whether these losses would be considered a RCBE for purposes of assessing an entity's responsibilities under Requirement R1 if an entity in the Eastern Interconnection has a 1,000 MW Most Severe Single Contingency. The first column explains the proposed unit or units lost, the middle column confirms whether the loss is an RCBE, and the third column explains the reason for the RCBE determination and whether this determination affects the Contingency Event Recovery Period.

Loss	**RBCE?**	**Reasoning**
750 MW Unit	No	The loss is less than 80 percent of the entity's MSSC.
850 MW Unit	Yes	The loss is less than the MSSC but is greater than 80 percent of the entity's MSSC. Measurement of the Contingency Event Recovery Period starts from the time of the loss of the unit and extends out 15 minutes.
1,000 MW unit	Yes	The loss is equal to the MSSC and is greater than 80 percent of the entity's MSSC. Measurement of the Contingency Event Recovery Period starts from the time of the loss of the unit and extends out 15 minutes.
750 MW unit and 200 MW Unit within 60 seconds	Yes	The total loss from the two events, which are aggregated because both events occurred within one minute of each other, is less than the MSSC but is greater than 80 percent of the MSSC. Measurement of the Contingency Event Recovery Period begins at the time of the loss of the 750 MW unit and extends out 15 minutes.

750 MW unit and then a 300 MW unit within 60 seconds	No	The total loss from the two events, which are aggregated because both events occurred within one minute of each other, is greater than the entity's MSSC.
750 MW unit loss and then 200 MW unit loss 90 seconds later	No	The two events do not occur within 60 seconds of each other, so this would be two separate Balancing Contingency Events, neither of which are an RCBE.
750 MW unit loss and then 300 MW unit loss 90 seconds later	No	The two events do not occur within 60 seconds of each other, so this would be two separate Balancing Contingency Events, neither of which are an RCBE.
850 MW unit loss and then 150 MW unit loss 90 seconds later	Yes (850 MW) No (150 MW)	The loss of the 850 MW unit is an RCBE because total loss of resources is equal to the entity's MSSC. The loss of the 150 MW unit is not combined with the loss of the 850 MW unit for purposes of RCBE determination because it occurred after one minute, and the loss of this unit alone is not an RCBE; however, because the second event occurred during the Contingency Event Recovery Period, the calculation of compliance will be adjusted for the loss of the second unit (i.e. assuming the ACE is zero at the time of the first event, compliance would require an ACE of -150 at the end of the 15 minute recovery period).
1,000 MW unit loss then 200 MW unit loss 10 minutes later	Yes (1000 MW) No (200 MW) R1.3.2 applies	The loss of the 1,000 MW unit is equal to the MSSC and is greater than 80 percent of the MSSC. The loss of the 200 MW unit is within the Contingency Reserve Recovery Period and is not an RCBE. Total loss of generation from both events is greater than the entity's MSSC and is within the Contingency Reserve Recovery Period, so under R1.3.2, the entity does not have to restore the Reporting ACE to defined values within the original Contingency Event Recovery Period under R1.1.

900 MW unit loss then 200 MW unit loss 16 minutes later	Yes (900 MW) No (200 MW) R3 applies R1.3.2 applies	The loss of the 900 MW unit is an RCBE because it is less than the MSSC but greater than 80 percent of the MSSC. No other generation is lost within the 15 minute Contingency Reserve Recovery Period. The loss of the 200 MW unit is after the Contingency Reserve Recovery Period and is not an RCBE. However, the loss of the 200 MW unit is within the Contingency Reserve Restoration Period, and when combined with the 900 MW unit loss, the loss is greater than the MSSC. Under R1.3.2, the entity does not have to restore the Reporting ACE within the Contingency Event Recovery Period under R1.1. Under R3, the Contingency Reserve Recovery Period is reset, and reserves would have to be recovered within 105 minutes from the second event.

Exhibit B

Calculating Most Severe Single Contingency

Calculating Most Severe Single Contingency

The Most Severe Single Contingency ("MSSC") for a Responsible Entity is dynamic in nature and is associated with an event due to a single contingency "that would result in the greatest loss (measured in MW) of resource output" used by the Responsible Entity at the time of the event to meet Firm Demand and export obligation (excluding export obligations for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

A single contingency could be one of the following events:

- A single line-to-ground or three-phase fault (whichever is more sever), with normal clearing, on any faulted generator, line, transformer, or shunt device; or
- Loss of any generator, line, transformer, or shut device without a fault; or
- A single pole block, with normal clearing, in a monopole or bipole high-voltage direct current system.

To effectively recover from an event or series of events and to meet obligations imposed by relevant requirements, a Responsible Entity should be aware of all of the above single contingencies, and applicable variations thereof, that would cause a resource output (in MW). For example, the MSSC may be the loss of a single generator, or the loss of multiple generators if all of the generators were connected to a common point. In another scenario, a step-up gathering transformer for a wind farm may be the MSSC. Further, if the loss of a transmission line is caused by one of the above single contingency events, this single lost transmission line transferring MWs to the BA *may* be the entity's MSSC.

All events that are considered single contingencies must result in a sudden loss of resource output and cause an instantaneous and unexpected change to the Responsible Entities Area Control Error. All single contingencies should be evaluated based upon the above criteria to determine if the Responsible Entity loses resource output. The determination of the Responsible Entity's MSSC is driven by the possibility of a physical event, and it is not an economic issue. Responsible Entities are compelled and highly motivated to determine the MSSC correctly since it allows them to maintain reliability and to be consistent and compliant with other NERC Reliability Standards such as BAL-001 and various TPL Standards.[1]

The following example scenarios, provided as illustration only, highlight the fact that the MSSC is generally dynamic because it depends on the output of a specific unit [or units] or the value of a firm import [or imports].

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[1] The standard drafting team for Project 2010-14.1 also notes that if the MSSC is too small and it is regularly exceeded, the entity will still have to regularly gamble on recovering ACE to meet BAAL. This "gaming" will likely result in a future violation. In addition, the Responsible Entities will come under scrutiny from their neighbors and may no longer be in compliance with BAL-002-2 or other standards.

Scenario 1

Suppose a Balancing Authority has one or more large units with the same rating, such as super critical coals units (1100 plus MW). Assuming these large units are the largest units on the system and one or more of these units will always be online, the output of one of these units *may* be MSSC for that Balancing Authority (notably, if one or more of these units are full output units, this MSSC may also be fixed for the year).

However, suppose that there is a hydro unit that is attached to the auxiliary buss of one of the super critical coal units described above, and the hydro unit will trip at the same time as the very large unit. In this case, the MSSC would be the output of the super critical coal unit plus the output of the hydro unit, thus making a dynamic MSSC.

Scenario 2

As illustrated by this scenario and Scenario 3, an entity's MSSC may be tied to the value of output traveling on a transmission line.

Suppose a Balancing Authority had a single high capacity transmission line, which is the only tie line to a neighboring Balancing Authority. If the neighboring Balancing Authority is the source of large firm import and the import would be cut as a result of the loss of the transmission, the firm import from this high capacity transmission line *may* be the MSSC. In this case, a Balancing Authority may choose to limit the firm import to some size to keep the MSSC at a value which is recoverable.

Scenario 3

Suppose a BA had several large hydro units tied to single line because of the remoteness of the facility. In this case, the MSSC *may* be the total output of those plants.

Scenario 4

Suppose a Balancing Authority has more than one large unit at a single site with a high reliability scheme, such as a breaker-an-a-half scheme and bus tie breakers, with many high capacity lines leaving the site. In this case, the total of the units would not be the MSSC for the Balancing Authority, because for all of the units to trip at one time would require a black hole scenario.[2]

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[2] The drafting team for Project 2010-14.1 notes that, for purposes of planning for compliance with TPL-001-4, an entity's MSSC would likely be the loss associated with the P1 contingencies; however, the team recognizes that circumstances may dictate different results.

Exhibit C

Proposed Reliability Standard BAL-002-2

BAL-002-2 Clean Version

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-2

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-2.

6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing

Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Real-time Operations**	**Medium**	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	**Operations Planning**	**Medium**	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the

			greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain annually the Operating Process.		Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	Responsible Entity's Most Severe Single Contingency..
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language in Requirement 1 Part 1.3.1 such that it addresses both current and future EEA process. In addition, the drafting team has added some clarifying language to 1.3.1 since comments were presented in previous postings expressing a concern only a Balancing Authority may request declaration of an EEA and a RSG cannot request an EEA. The standard drafting team's intent has always been if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

Rationale for Requirement R2:

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Rationale for Requirement R3:

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

BAL-002-2 Redline Version

A. Introduction

~~1.~~ Title: ~~Disturbance Control Performance~~

~~2. Number: BAL-002-1~~

1. ~~Purpose: The purpose of the~~ Disturbance Control Standard ~~(DCS) is to~~ – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-2

3. **Purpose:** To ensure the Balancing Authority ~~is able to utilize its Contingency~~or Reserve ~~to balance~~Sharing Group balances resources and demand and ~~return Interconnection frequency within~~ returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable ~~Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load~~Balancing Contingency Event.

4. **Applicability:**

~~4.1. Balancing Authorities~~

~~4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)~~

~~4.3. Regional Reliability Organizations~~

~~5. (Proposed) Effective Date: The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~

~~B. Requirements~~

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

4.1. Responsible Entity

4.1.1. Balancing Authority

4.1.1.1. A Balancing Authority ~~may elect to fulfill its Contingency Reserve obligations by participating as a~~ that is a member of a Reserve Sharing Group~~. In such cases, the~~ is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

4.1.2. Reserve Sharing Group ~~shall have~~

5. **Effective Date:** See the ~~same responsibilities~~Implementation Plan for BAL-002-2.

6. Background:

Reliably balancing an Interconnection requires frequency management and ~~obligations as each~~all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing ~~Authority with respect to monitoring and meeting~~Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~R1.1.~~1.1. within the ~~requirements of Standard BAL-002.~~Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

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

~~**R2.1.** The minimum reserve requirement for the group.~~

~~**R2.2.** Its allocation among members.~~

- ~~The permissible mix of~~zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating ~~Reserve – Spinning and~~ Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each ~~Reserve – Supplemental that may be~~ Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

~~R2.3.~~ **R3.** Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve~~.~~ Restoration

Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~**R2.4.** The procedure for applying~~**M3.** Each Responsible Entity will have documentation demonstrating its Contingency Reserve ~~in practice.~~

~~**R2.5.** The limitations, if any, upon the amount of interruptible load that may be included.~~

~~**R2.6.** The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.~~was restored

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

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

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

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

~~**R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.~~

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

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

~~or~~

~~**R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its~~

~~equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.~~

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

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

~~**R6.2.** The default Contingency Reserve Restoration Period is 90 minutes.~~

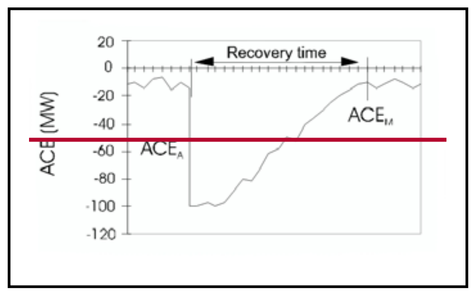
~~C. Measures~~

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

~~For loss of generation:~~

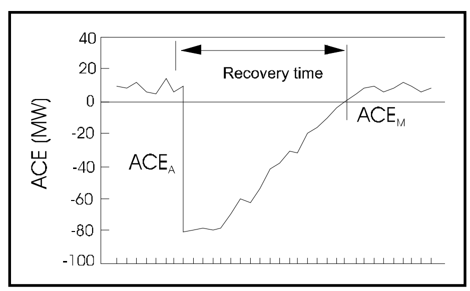
~~if $ACE_A < 0$~~
~~then~~

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



~~if $ACE_A \geq 0$~~
~~then~~

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



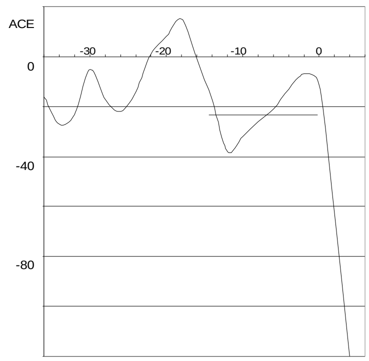
~~where:~~

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

~~The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be~~

~~measured as a change in ACE since governor response and AGC response may introduce error.~~

~~The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.~~



~~The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.~~

~~D.~~C. Compliance

1. Compliance Monitoring Process

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

~~Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th).~~

~~The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.~~

1.1. Compliance Enforcement Authority

~~Regional Entity.~~

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. Evidence Retention

The following evidence retention period(s) 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.

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.

~~1.2.~~1.3. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~Assessment Processes:

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

~~1.3.~~ As defined in the NERC Rules of Procedure, "Compliance Monitoring and ~~**Enforcement**~~Assessment Processes~~:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.4. Data Retention**~~

~~The data that support the calculation of DCS are~~" refers to ~~be retained in electronic form for at least a one-year period. If~~ the ~~DCS data for a Reserve~~

~~Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding~~identification of the ~~data,~~ processes that will be used to evaluate data or information for the ~~data are to be saved beyond~~purpose of assessing performance or outcomes with the ~~normal retention period until the question is formally resolved~~associated Reliability Standard.

~~1.5.~~1.4. Additional Compliance Information

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

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

~~**Multiple Contingencies within the Reportable Disturbance Period** – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.~~

~~**Multiple Contingencies within the Contingency Reserve Restoration Period** – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.~~

~~**Levels of Non-**~~The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

~~2.~~ Table of Compliance Elements

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

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

~~3. Violation Severity Levels (no changes)~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.

			to document a Reportable Balancing Contingency Event.			
R2.	**Operations Planning**	**Medium**	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain annually the Operating Process.	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency..
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

~~E.~~D. Regional ~~Differences~~Variances

None ~~identified~~.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	~~TBD~~January 10, 2011	~~Modified to address Order No. 693 Directives contained in paragraph 321.~~FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	~~Revised.~~
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language in Requirement 1 Part 1.3.1 such that it addresses both current and future EEA process. In addition, the drafting team has added some clarifying language to 1.3.1 since comments were presented in previous postings expressing a concern only a Balancing Authority may request declaration of an EEA and a RSG cannot request an EEA. The standard drafting team's intent has always been if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

Rationale for Requirement R2:

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Rationale for Requirement R3:

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

Exhibit D

Implementation Plan

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Implementation Plan

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

BAL-002-2

Approvals Required

BAL-002-2 – Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

Applicable Entities

Balancing Authority[1]

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

[1] A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. *See* Section A.4.1.1.1, BAL-002-2.

Reliability Standard BAL-002-1, Disturbance Control Performance shall be retired immediately prior to the effective date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

The existing definition of Contingency Reserve should be retired immediately prior to the effective date of BAL-002-2, in the particular jurisdiction in which the new standard is becoming effective.

Exhibit E

BAL-002-2 Background Document

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BAL-002-2
Background Document

September 2015

RELIABILITY | ACCOUNTABILIT

Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple a methodology to adequately address all of these interactions. The suite of NERC Standards work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity’s MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002),

this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert.

For additional technical justification for exemption from R1 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance.

In addition, the standard drafting team (SDT) through R1 Part 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the

number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

- If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

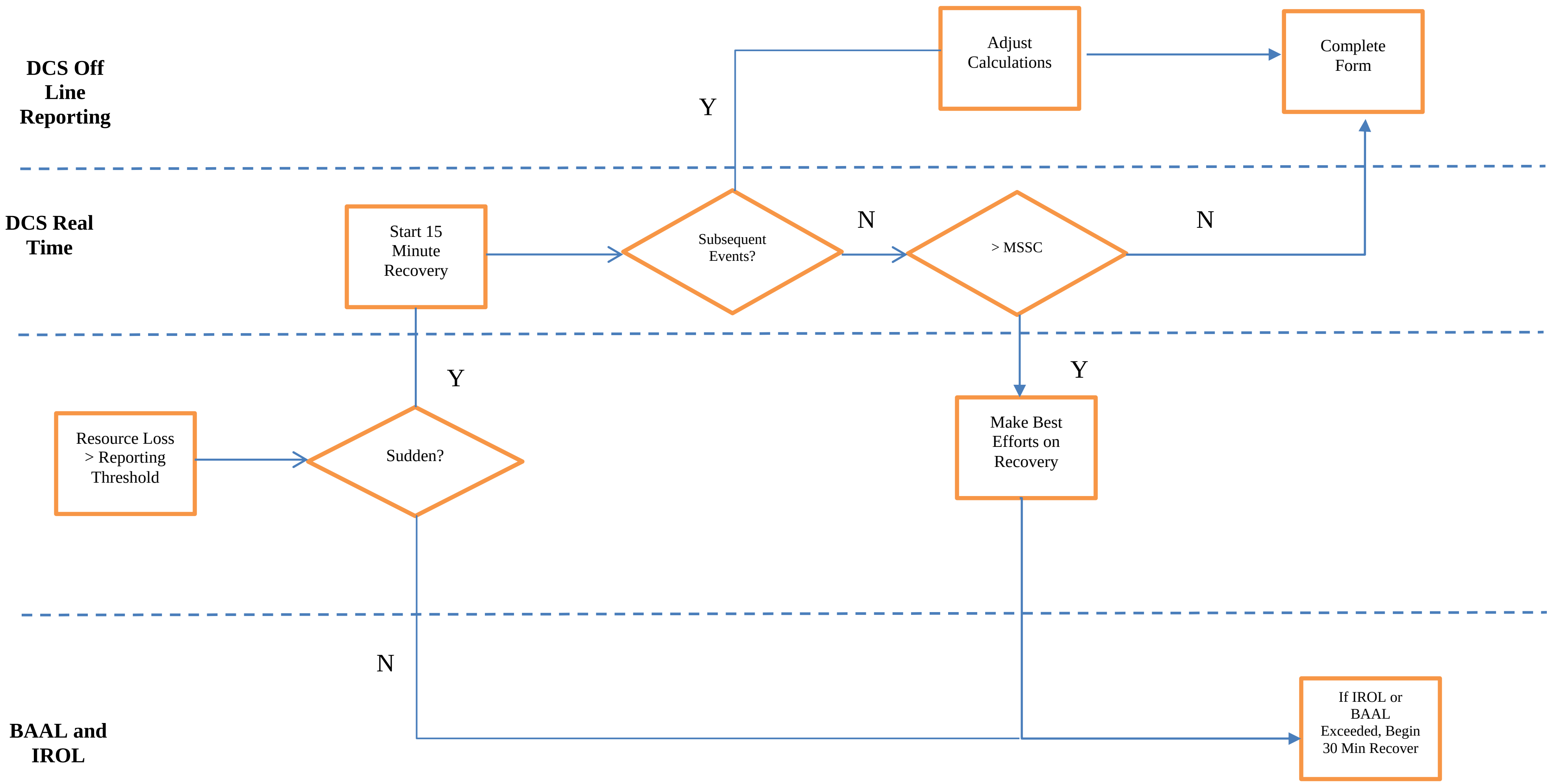
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve be at least equal to the applicable entity's Most Severe Single Contingency and a definition of Most Severe Single Contingency. Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, Requirement R3 addresses restoration of the reserves.

Requirement 3

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events. This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes.

Attachment 1

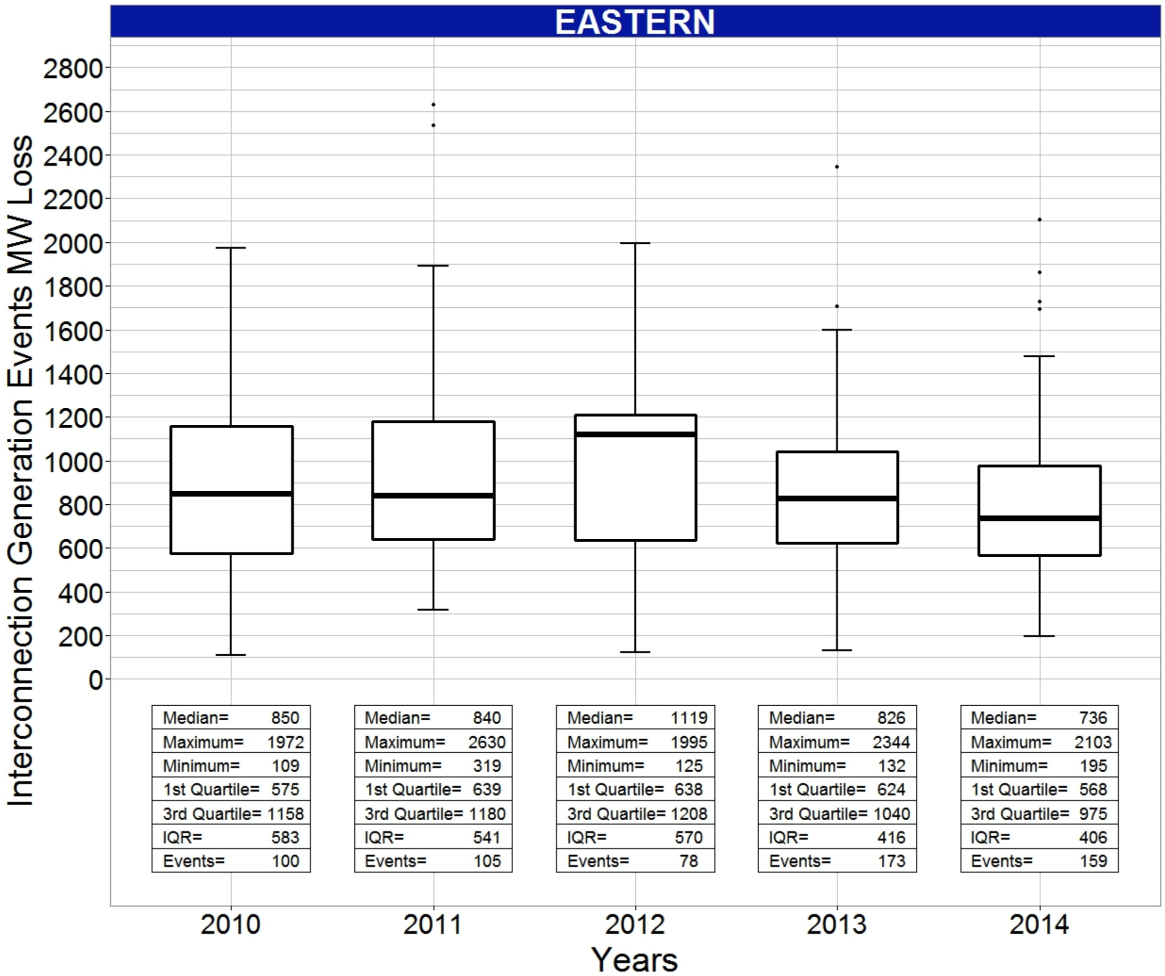
NERC Interconnections 2009-2013

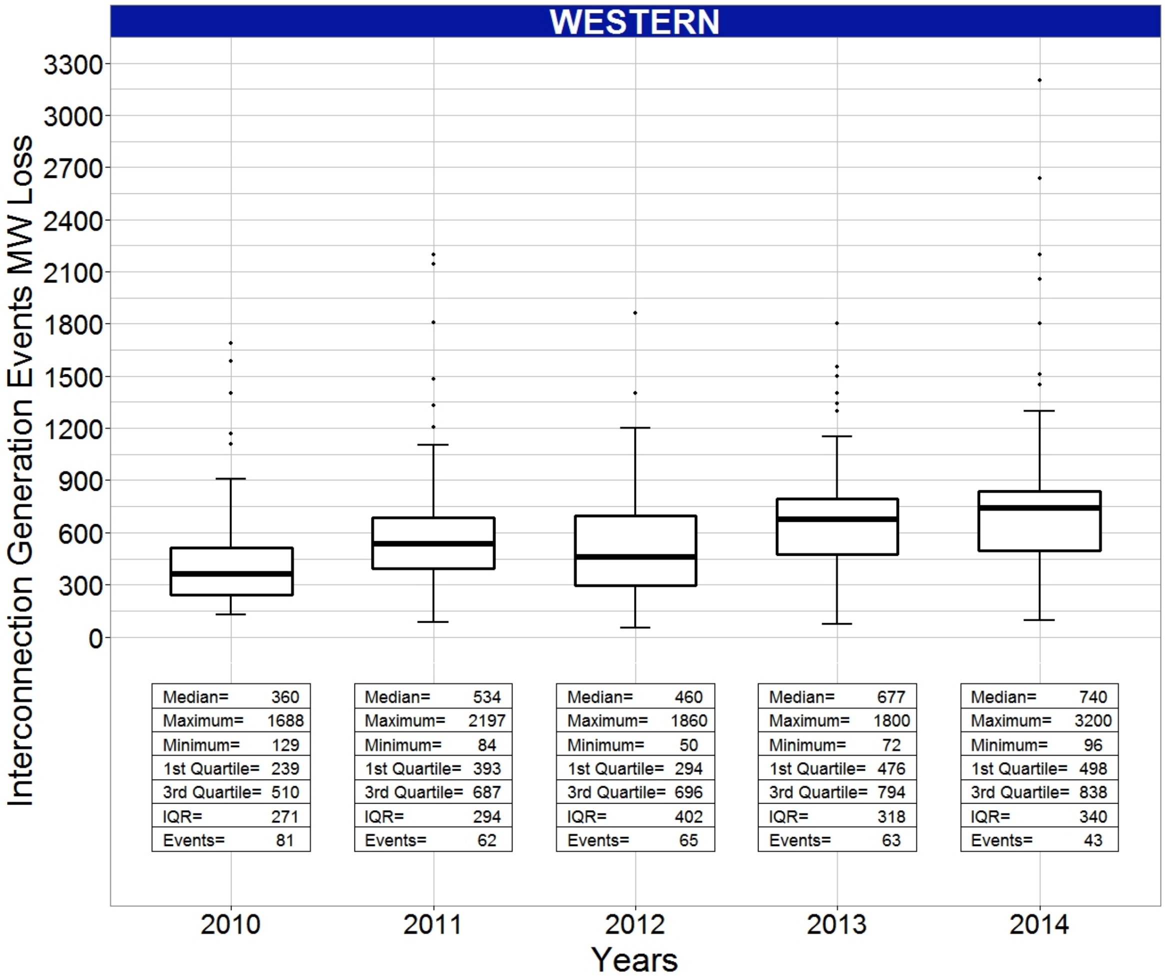
Frequency Events Loss MW Statistics

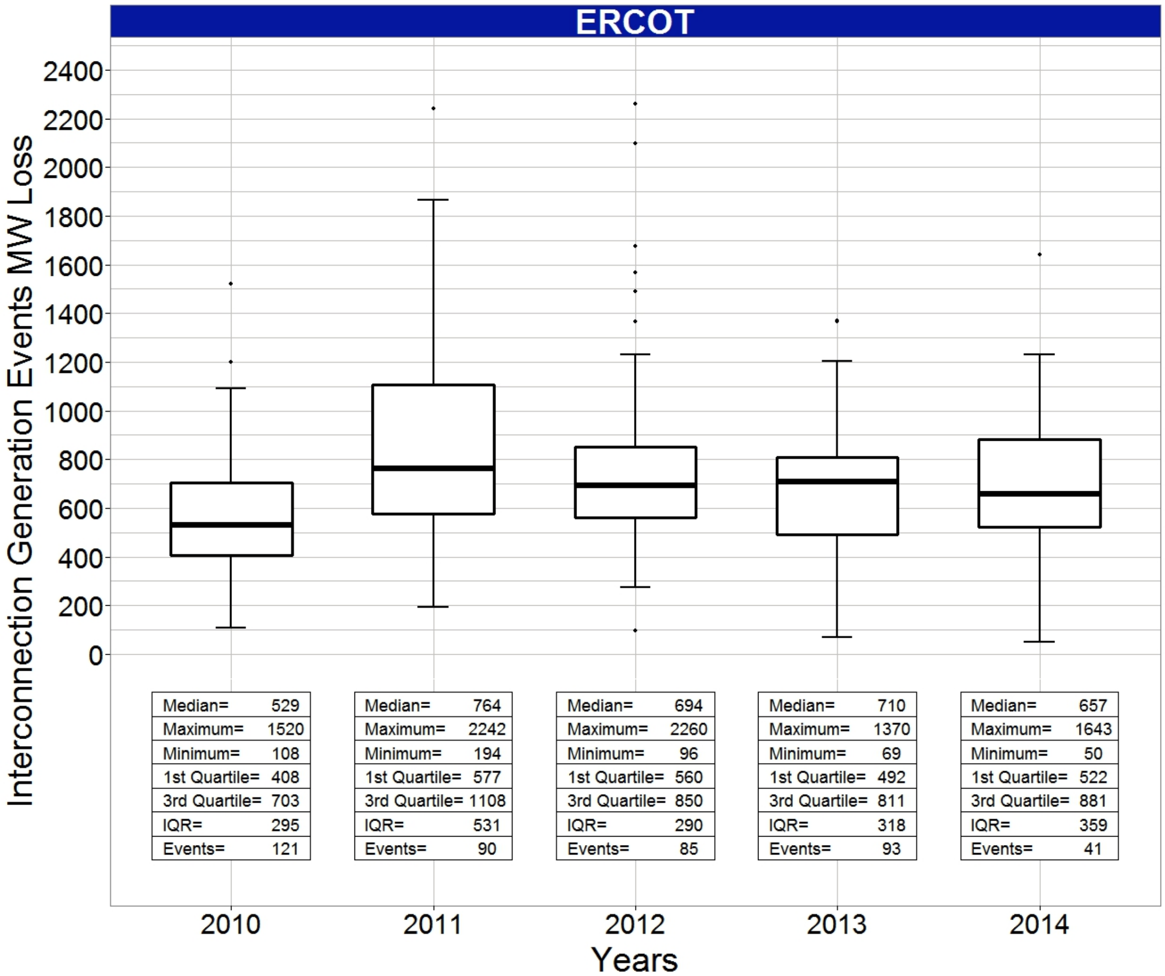
For: NERC BARC Standard Drafting Team

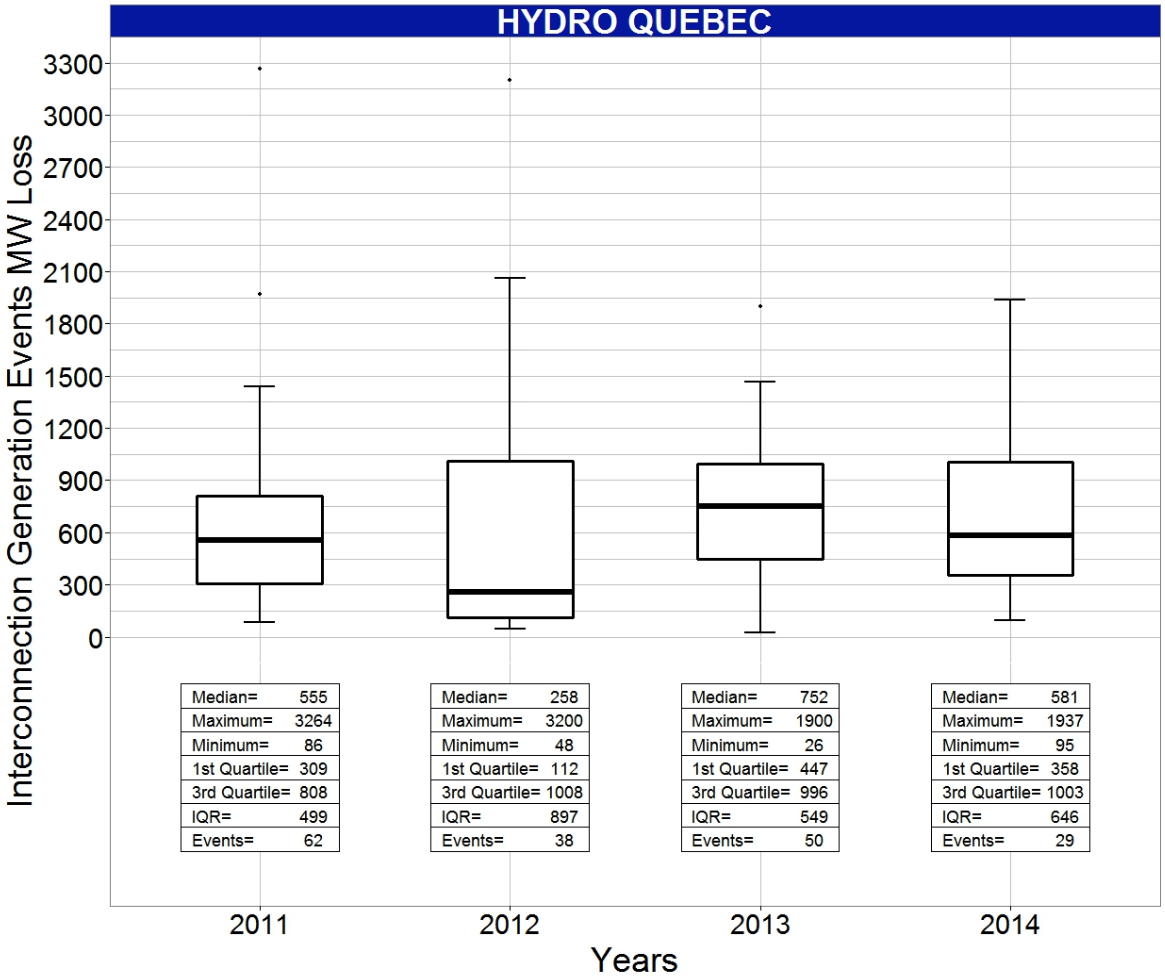
Prepared by: CERTS

Date: October 15, 2013


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: “Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated.”

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

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[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

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[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.

- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.

- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

Exhibit G

Analysis of Violation Risk Factors and Violation Severity Levels

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-002-2, Contingency Reserve for Recovery from a Balancing Contingency Event. 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

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[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 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

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-002-2:

There are two requirements in BAL-002-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-002-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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 and approved reliability standards BAL-001-1 and BAL-003-1.
- 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

violation, in itself, 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-002-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. All of the requirements in BAL-002-2 are assigned a “Medium” VRF. Requirement R2 is similar in scope to Requirement R1. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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 and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. All of the requirements in BAL-002-2 are assigned a “Medium” VRF. . This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2 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-002-2 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-002-2 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 levels of noncompliance performance.	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.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-002-2 Requirement R3:

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
R3.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	This is similar to the current BAL-002-1 Requirement R3.1. 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 amount of contingency reserve recovered.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Exhibit H

Summary of Development History and Complete Record of Development

Summary of Development History

The development record for proposed Reliability Standard BAL-002-2 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 selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] 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 K**.

II. Standard Development History

A. Standard Authorization Request Development

The Standards Committee ("SC") approved the merger of Project 2007-05 (Balancing Authority Controls) and Project 2007-18 (Reliability-based Controls) to create Project 2010-14 (Balancing Authority Reliability-based Controls) on July 28, 2010. The SC subsequently approved the division of Project 2010-14 (Balancing Authority Reliability-based Controls) into two phases and the transition of Phase 1 (Project 2010- 14.1, Balancing Authority Reliability-based Controls – Reserves) into formal standards development on July 13, 2011. A Standard Authorization Request ("SAR") for Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Controls: Reserves was posted for a 30-day formal comment period from June 4, 2012 through July 3, 2012.

B. Initial and First Comment Period, Initial Ballot, and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for the initial formal 30-day public comment period from June 4, 2012 through July 3, 2012 and the first formal 45-day public comment period from March 12, 2013 through April 25, 2013. Several associated documents were posted for consideration and approval together with the draft standard, including the Unofficial Comment Form, Mapping Document, and Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") Justification Documents. The Non-Binding Poll reached quorum at 86.46% of the ballot pool, and the standard and associated documents received support from only 43.96% of the voters.

The standard was posted for the initial 10-day ballot simultaneously with the first formal 45-day public comment period from April 16, 2013 through April 25, 2013. The initial ballot reached quorum at 88.51% of the ballot pool, and the standard and associated documents received support from only 42.75% of the voters. There were 55 sets of comments, including comments from approximately 179 different individuals and approximately 108 companies, representing all 10 industry segments.[3]

C. Second Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for an additional 45-day formal comment period from August 2, 2013 through September 17, 2013, with an additional parallel ballot held from September 6, 2013 through September 17, 2013. The

[3] NERC, *Consideration of Comments*, Project 2010-14.1, *available at* *http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/Comment_Report_2010-14.1_BARC_BAL-002-2-20130731.pdf*.

additional ballot reached quorum at 76.15% of the ballot pool, and the standard and associated documents received support from 58.23% of the voters. The related Non-Binding Poll reached quorum at 75.69% of the ballot pool, and the standard and associated documents received support from 59.66% of the voters. There were 35 sets of comments, including comments from approximately 100 different individuals and approximately 66 companies, representing 7 of the 10 industry segments.[4]

D. Third Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for an additional 45-day formal comment period from October 28, 2013 through December 11, 2013, with an additional parallel ballot held from December 2, 2013 through December 12, 2013. The additional ballot reached quorum at 75.29% of the ballot pool, and the standard and associated documents received support from 64.24% of the voters. The related Non-Binding Poll reached quorum at 76.62% of the ballot pool, and the standard and associated documents received support from 66.67% of the voters. There were 32 sets of comments, including comments from approximately 90 different individuals and approximately 70 companies, representing all 10 industry segments.[5]

E. Fourth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for an additional 45-day formal comment period from August 19, 2014 through October 3, 2014, with an additional parallel ballot held from September 23, 2014 through October 3, 2014. The

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4 NERC, *Consideration of Comments*, Project 2010-14.1, (October 15, 2013), *available at* *http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/Project2010-141BARCBAL-002-2SummaryofComments-20131021.pdf*.

5 NERC, *Consideration of Comments*, Project 2010-14.1, (August 2014), *available at* *http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/Project%202010-14%201%20BARC%20BAL-002-2%20Summary%20of%20Comments%20-%202014%2006%2001.pdf*.

additional ballot reached quorum at 79.94% of the ballot pool, and the standard and associated documents received support from 46.73% of the voters. The related Non-Binding Poll reached quorum at 76.49% of the ballot pool, and the standard and associated documents received supportive opinions from only 54.12% of the voters. There were 28 sets of comments, including comments from approximately 109 different individuals and approximately 74 companies, representing all 10 industry segments.[6]

F. Fifth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for an additional 45-day formal comment period from January 29, 2015 through March 18, 2015, with an additional parallel ballot held from March 6, 2015 through March 18, 2015. The additional ballot reached quorum at 77.29% of the ballot pool, and the standard and associated documents received support from 59.83% of the voters. The Non-Binding Poll reached quorum at 75.86% of the ballot pool, and the standard and associated documents received supportive opinions from 70.93% of the voters. There were 24 sets of comments, including comments from approximately 116 different individuals and approximately 80 companies, representing 9 of the 10 industry segments.[7]

G. Sixth Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard BAL-002-2 was posted for an additional 45-day formal comment period from July 7, 2015 through August 20, 2015, with an additional parallel ballot held from August 11, 2015 through August 21, 2015. The additional ballot

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[6] NERC, *Consideration of Comments*, Project 2010-14.1, (January 2015), *available at* http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/Project%202010-14%201%20BARC%20BAL-002-2%20Summary%20of%20Comments%20-%202015%2001%2026.pdf.

[7] NERC, *Consideration of Comments*, Project 2010-14.1, *available at* http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/2010-14_1_Consideration_of_Comments_BARC_BAL-002-2_20150701.pdf.

reached quorum at 75.92% of the ballot pool, and the standard and associated documents received support from 69.26% of the voters. The Non-Binding Poll reached quorum at 79.42% of the ballot pool, and the standard and associated documents received supportive opinions from 69.28% of the voters. There were 33 sets of comments, including comments from approximately 87 different individuals and approximately 63 companies, representing 8 of the 10 industry segments.[8]

H. Final Ballot

Proposed Reliability Standard BAL-002-2 was posted for a 10-day final ballot period from September 29, 2015 through October 8, 2015. The ballot for the proposed Reliability Standard and associated documents reached quorum at 84.28% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 74.61% of the voters.[9]

I. Board of Trustees Adoption

Proposed Reliability Standard BAL-002-2 was adopted by the NERC Board of Trustees on November 5, 2015.[10]

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[8] NERC, *Consideration of Comments*, Project 2010-14.1, *available at* http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/2010-14_1_BAL-002-2_Consideration_of_Comments_09292015.pdf.

[9] NERC, *Standards Announcement*, Project 2010-14.1, *available at* http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/2010-14.1_BARC_BAL-002-2_FB_Results_Word_Announce_10092015.pdf.

[10] NERC, *Board of Trustees Agenda Package*, Agenda Item 4.c. (Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls (BAL-002), available at http://www.nerc.com/gov/bot/botquarterlyitems/Board_Agenda_Package_November_2015_v3a.pdf.

Complete Record of Development

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

Status
A final ballot for **BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event** concluded **8 p.m. Eastern, Thursday, October 8, 2015**. The voting results can be accessed via the links below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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
Draft 7 BAL-002-2 Clean **(142)** | Redline to Last Posted **(143)** Implementation Plan Clean **(144)** | Redline to Last Posted **(145)** **Supporting Materials** Background Document Clean **(146)** | Redline to Last Posted **(147)**	Final Ballot Info **(150)** Vote Revised Draft RSAW Info	09/29/15 - 10/08/15	Summary **(151)** Ballot Results **(152)**	

Revised Draft Reliability Standard Audit Worksheet (RSAW)				
VRF/VSL Justification Clean (148) | Redline to Last Posted (149)	Posted for Information October 6, 2015			
Draft 7 BAL-002-2 Clean (125) | Redline to Last Posting (126) Implementation Plan Clean (127) | Redline to Last Posting (128) **Supporting Materials** Unofficial Comment Form (Word) (129) Background Document Clean (130) | Redline to Last Posting (131) Mapping Document Clean (132) | Redline to Last Posting (133) CR Form 1	Additional Ballot and Non-binding Poll The ballot and non-binding poll for this posting are **additional**. Since the previous ballot pools for this project are outdated, new ballot pools are being formed in the SBS. Updated Info (136) Info (137) Vote	08/11/15 - 08/21/15 Non-binding Poll extended an additional day (from 8/20/15) to reach quorum	Summary (138) Ballot Results (139) Non-binding Poll Results (140)	
	Comment Period Info (134) Submit Comments	07/07/15 - 08/20/15	Comments Received (135)	Consideration of Comments (141)
	Join Ballot Pools If you previously joined the ballot pools for BAL-002-2, you **must** join these ballot pools to cast a vote. Previous BAL-002-2 ballot pool members **will not**be carried over to these ballot pools.	07/07/15 - 08/05/15		
	Please send RSAW feedback to: RSAWfeedback@nerc.net	07/22/15 - 08/20/15		

Draft RSAW				
Draft 6 BAL-002-2 Clean **(109)** | Redline to Last Posting **(110)** Implementation Plan Clean **(111)** | Redline to Last Posting **(112)** **Supporting Materials** Unofficial Comment Form (Word) **(113)** Background Document Clean **(114)** | Redline to Last Posting **(115)** Mapping Document **(116)** CR Form 1 Draft RSAW	Additional Ballot and Non-binding Poll Updated Info **(119)** Info **(120)** Vote	03/06/15 – 03/18/15 Extended an additional day to reach quorum	Summary **(121)** Ballot Results **(122)** Non-binding Poll Results **(123)**	
	Comment Period Info **(117)** Submit Comments	01/29/15 – 03/18/15	Comments Received **(118)**	Consideration of Comments **(124)**
	Please send RSAW feedback to: RSAWfeedback@nerc.net	02/16/15 - 03/18/15		
Draft 5 BAL-002-2 Clean **(93)** |Redline to Last Posting **(94)** Implementation Plan Clean **(95)** |Redline to Last Posting **(96)** **Supporting Materials** Unofficial Comment Form (Word) **(97)** Background Document Clean **(98)** |Redline to Last Posting **(99)** Mapping Document **(100)** CR Form 1 Draft RSAW	Additional Ballot and Non-binding Poll Updated Info **(103)** Info **(104)** Vote	09/23/14 – 10/03/14	Summary **(105)** Ballot Results **(106)** Non-binding Poll Results **(107)**	Consideration of Comments **(108)**
	Comment Period Info **(101)** Submit Comments	08/19/14 – 10/03/14	Comments Received **(102)**	
	Please send RSAW feedback to: RSAWfeedback@nerc.net	09/11/14 - 10/03/14		

Draft 4 BAL-002-2 Clean (76) |Redline to Last Posting (77) Implementation Plan Clean (78) |Redline to Last Posting (79) **Supporting Materials** Unofficial Comment Form (Word) (80) Background Document Clean (81) |Redline to Last Posting (82) Mapping Document Clean (83) |Redline to Last Posting (84) CR Form 1	Additional Ballot and Non-binding Poll Updated Info (87) Info (88) Vote	12/02/13 - 12/12/13	Summary (89) Ballot Results (90) Non-binding Poll Results (91)	Consideration of Comments (92)
	Comment Period Info (85) Submit Comments	10/28/13 - 12/11/13	Comments Received (86)	
Draft 3 BAL-002-2 Clean (59) | Redline to Last Posting (60) Implementation Plan Clean (61) | Redline to Last Posting (62) **Supporting Materials** Unofficial Comment Form (Word) (63) Background Document Clean (64) | Redline to Last Posting (65) VRF/VSL Justification (66) Mapping Document Clean (67) | Redline to Last Posting (68) CR Form 1	Additional Ballot Updated Info (71) Vote	09/06/13 - 09/17/13	Summary (72) Ballot Results (73) Non-binding Poll Results (74)	Consideration of Comments (75)
	Comment Period Info (69) Submit Comments	08/02/13 - 09/17/13	Comments Received (70)	
BAL-001-2 Clean (46) | Redline to Last Posting (47) Implementation Plan	Final Ballot Info (56)	07/16/13 - 07/25/13		

Clean (48) | Redline to Last Posting (49) **Supporting Materials** Background Document Clean (50) | Redline to Last Posting (51) VRF/VSL Justification Clean (52) | Redline to Last Posting (53) Mapping Document Clean (54) | Redline to Last Posting (55)	Vote		Summary (57) Ballot Results (58)	
BAL-001-2 Clean (19) | Redline to Last Posting (20) Implementation Plan Clean (21) | Redline to Last Posting (22) **BAL-002-2** Clean (23) | Redline to Last Posting (24) Implementation Plan Clean (25) | Redline to Last Posting (26) **BAL-013-1** Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting **Supporting Materials** Unofficial Comment Forms (Word) BAL-001-2 (27) BAL-002-2 (28)	Initial Ballots and Non-binding Polls Info (41) Vote	04/16/13 - 04/25/13	Summary (42) Ballot Results: BAL-002-2 BAL-001-2 (43) BAL-013-1 Non-binding Poll Results: BAL-001-2 (44) BAL-002-2 (45) BAL-013-1	
	Formal Comment Period Info (36) Submit Comments BAL-001-2 BAL-002-2 BAL-013-1	03/12/13 - 04/25/13	Comments Received: BAL-001-2 (37) BAL-002-2 (38) BAL-013-1	Consideration of Comments: BAL-001-2 (39) BAL-002-2 (40)

BAL-013-1 **Background Documents** BAL-001-2 Clean **(29)** | Redline to Last Posting **(30)** BAL-002-2 Clean **(31)** BAL-013-1 Clean | Redline to Last Posting **Mapping Documents** BAL-001-2 **(32)** BAL-002-2 **(33)** **VRF/VSL Justification** BAL-001-2 **(34)** BAL-002-2 **(35)** BAL-013-1	Join Ballot Pools	03/12/13 - 04/10/13		
Draft 2 **BAL-012-1** Clean | Redline to Last Posting **Supporting Materials** Unofficial Comment Form (Word) Background Document Clean | Redline to Last Posting Implementation Plan	Initial Ballot and Non-binding Poll Updated Info Info Vote	1/4/2013 – 1/14/2013	Summary Ballot Results Non-binding Poll Results	
	Formal Comment Period Info	11/30/2012 – 1/14/2013	Comments Received	

Clean | Redline to Last Posting VRF/VSL Justification	Submit Comments Join Ballot Pool	11/30/2012 – 1/3/2013		
Draft 1 **BAL-001-1** Clean **(9)** **Supporting Materials** Unofficial Comment Form (Word) **(10)** BAL-001-0.1a **(11)** Background Document **(12)** Implementation Plan **(13)** Mapping Document **(14)** VRF/VSL Justification **(15)**	Formal Comment Period Info **(16)** Submit Comments Comment Form - BAL-001-1	6/4/2012 -7/3/2012	Comments Received **(17)**	Consideration of Comments **(18)**
Draft 1 **BAL-002-2** Clean **(1)** **Supporting Materials** Unofficial Comment Form (Word) **(2)** BAL-002-1 **(3)** Background Document **(4)** Implementation Plan **(5)** Mapping Document **(6)**	Formal Comment Period Info **(7)** Submit Comments Comment Form - BAL-002-2	6/4/2012 -7/3/2012	Comments Received **(8)**	

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	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	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 Control, 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. Third posting	March/April 2013
4. Successive ballot	May 2013
5. Recirculation Ballot	August 2013

6. NERC BOT adoption.	September 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 Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of Generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facilities resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facilities;
   b. And, that causes an unexpected change to the responsible entity's ACE;
   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.

B. Sudden Loss of Non-Interruptible Import:
   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment that causes an unexpected change to the responsible entity's ACE.

C. Unexpected Failure of Generation to Maintain or Increase:
   a. Due to
      i. Inability to start a unit the responsible entity planned to bring online at that time (for reasons other than lack of fuel), or
      ii. Internal plant equipment problems that force the generator to be ramped down or taken offline;
   b. And that, even if not an immediate cause of an unexpected change to the responsible entity's ACE, will, in the responsible entity's judgment, leave the responsible entity unable to maintain its ACE following the failure, unless it deploys Contingency Reserve.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority, to meet firm system load and non-interruptible export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event: Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW.

Contingency Event Recovery Period: A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value: The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,

or

The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

A. Introduction

1. **Title: Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Contingency Event.

4. **Applicability:**

   4.1. Balancing Authority

   4.2. 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. Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period: *[Violation Risk Factor:][Time Horizon:]*

- The Balancing Authority or Reserve Sharing Group returned its ACE to:
  - Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, Or
  - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.
- Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to

its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

C. Measures

M1. Each Balancing Authority or Reserve Sharing Group shall have, and provide upon request, evidence; such as computer logs or operator logs, with date and time of occurrence to show compliance with Requirement R1.

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 or Reserve Sharing Group shall retain data or evidence to show compliance for the current year, plus three calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Reserve Sharing Group 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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group.

A Balancing Authority or Reserve Sharing Group may use Contingency Reserve for any Balancing Contingency Event.

A Balancing Authority or Reserve Sharing Group may optionally reduce the 80 percent threshold, upon written notification to the Regional Entity.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				
R2				
R3				
R4				

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Contingency Reserve for Recovery from a Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Contingency Reserve for Recovery from a Contingency Event. Comments must be submitted using 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.

Background Information:

Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve Plan.

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 five new terms to be used with this standard.**

Balancing Contingency Event:

Any single event described in subsections (A), (B), or (C) below, or any series of such otherwise single events with each separated from the next by less than one minute.

A. Sudden Loss of Generation:
   a. Due to
      i. unit tripping,
      ii. loss of generator interconnection facilities resulting in isolation of the generator from the Bulk Electric System or from the Responsible Entity's electric system, or
      iii. sudden unplanned outage of transmission facilities;
   b. And, that causes an unexpected change to the Responsible Entity's ACE;
   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.

B. Sudden Loss of Non-Interruptible Import:
   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the Responsible Entity's ACE.

C. Unexpected Failure of Generation to Maintain or Increase:
   a. Due to
      i. inability to start a unit the Responsible Entity planned to bring online at that time (for reasons other than lack of fuel), or
      ii. internal plant equipment problems that force the generator to be ramped down or taken offline;
   b. And that, even if not an immediate cause of an unexpected change to the Responsible Entity's ACE, will, in the Responsible Entity's judgment, leave the Responsible Entity unable to maintain its ACE following the failure unless it deploys contingency reserve.

Most Severe Single Contingency (MSSC):

The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority, to meet firm system load and non-interruptible export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event:

Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW.

Contingency Event Recovery Period:

A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period:

A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the Amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value:

The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,

or

The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

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

☐ Yes

☐ No

Comments:

2. The proposed Purpose Statement for the draft standard is:

To ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Contingency Event.

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

☐ Yes

☐ No

Comments:

3. **The BARC SDT has developed Requirement R1 to determine whether a Balancing Authority (BA) or Reserve Sharing Group (RSG) has implemented its Contingency Reserve plan and determine whether a BA or RSG met ACE recovery equal to the BA's or RSG's Most Severe Single Contingency.**

   R1. Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period:

   - The Balancing authority or Reserve Sharing Group returned its ACE to
     - Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or
     - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.
   - Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

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

   ☐ Yes

   ☐ No

   Comments:

4. **The BARC SDT has developed a Measure for the proposed Requirement within this standard. Do you agree with the proposed Measure in this standard? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

5. **The BARC SDT has developed a document "BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event 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:

6. **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:

7. **Do you have any other comment on BAL-002-2, not expressed in the questions above, for the BARC SDT?**

   Comments:

A. Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-1
3. **Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   - **4.3.** Regional Reliability Organizations
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

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

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

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

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

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

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

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

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

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

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

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

or

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

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

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

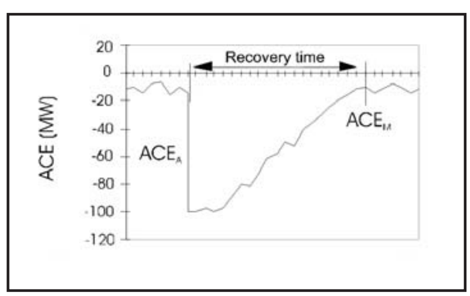
R6.2. The default Contingency Reserve Restoration Period is 90 minutes.

C. Measures

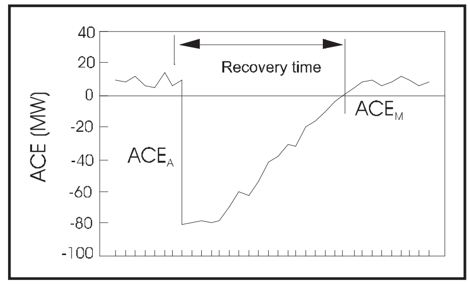
M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions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

For loss of generation:

if $ACE_A < 0$
then



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



if $ACE_A \geq 0$
then

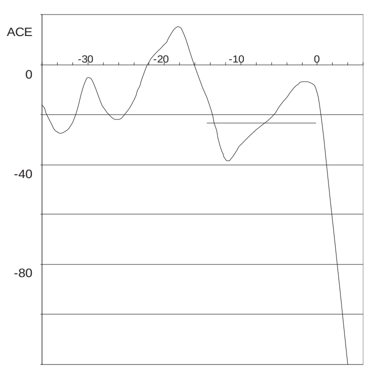
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

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

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

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

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

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

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

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

1.5. Additional Compliance Information

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

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

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

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

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

3. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 321.	Revised.

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RELIABILITY CORPORATION

BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

January 2012

RELIABILITY | ACCOUNTABILITY

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Table of Contents

Contents

Introduction

Since loss of generation occurs so often and impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and associated timeframes. This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. The original Standards Authorization Request (SAR), approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve plan.

Background and Rationale by Requirement

Requirement 1

R1. Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can demonstrate that, within the Contingency Recovery period:

- The Balancing Authority or Reserve Sharing Group returned its ACE to:
  - Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or
  - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.
- Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or

Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1. Its objective is to measure the successful implementation of the Contingency Reserve Plan for Reportable Contingency Events. It requires the Balancing Authority to have Contingency Reserve available to recover from events that would be less than or equal to the Balancing Authority's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the BA or RSG must demonstrate for compliancy evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows BAs and RSGs to have clear way to show compliance and support the Interconnection to full extent of MSSC.

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Implementation Plan

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

Implementation Plan for BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

> **Balancing Contingency Event:** Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events with each separated from the next by less than one minute.
>
> A. Sudden Loss of Generation:
>   a. Due to
>   i. unit tripping,
>   ii. loss of generator Interconnection Facilities resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
>   iii. sudden unplanned outage of transmission Facilities;
>   b. And that causes an unexpected change to the responsible entity's ACE;
>   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.
>
> B. Sudden Loss of Non-Interruptible Import:
>   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the responsible entity's ACE.
>
> C. Unexpected Failure of Generation to Maintain or Increase:
>   a. Due to

i. Inability to start a unit the responsible entity planned to bring online at that time (for reasons other than lack of fuel), or

ii. Internal plant equipment problems that force the generator to be ramped down or taken offline;

b. And that, even if not an immediate cause of an unexpected change to the responsible entity's ACE, will, in the responsible entity's judgment, leave the responsible entity unable to maintain its ACE following the failure unless it deploys Contingency Reserve.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority to meet firm System Load and non-interruptible export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event: Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency, or 500 MW.

Contingency Event Recovery Period: A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value: The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,
or
The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 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 pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same	This Requirement has been moved into BAL-002-2 "Additional Compliance Information"	1.4. Additional Compliance Information A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. A Balancing Authority or Reserve Sharing Group may use Contingency Reserve for any Balancing Contingency Event.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members. R2.3. The permissible mix of	This Requirement has been moved into BAL-012-0 Requirements R2 and R4	BAL-012-0 Requirement R2 R2. Each Balancing Authority and Reserve Sharing Group shall, once each calendar year with no more that 15 calendar months between intervals, document its annual plan for Contingency Reserve used to recover from Balancing Contingency Events addressing each of the following: [Violation Risk Factor:] [Time Horizon:] 2.1. The determination of the Balancing Authority's or Reserve Sharing Group's Contingency Reserve margin.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		2.2. The types of resources and the portion of their capacity capable of reducing the Balancing Authority's Area Control Error in response to each of the following 2.2.1. Balancing Contingency Event 2.2.2. Events associated with Energy Emergency Alert 2, and 2.2.3. Events associated with Energy Emergency Alert 3. 2.3. The control of supply and demand resources such as generators, controllable Loads and energy storage devices. 2.4. The incorporation of energy import and export schedules by entities within the Balancing Authority Area and with other Balancing Authorities. 2.5. The characteristics: such as capabilities, constraints and volatilities, of the resources operating inside the Balancing Authority Area. 2.6. The characteristics: such as capabilities, constraints and volatilities, of the Load operating

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		inside the Balancing Authority Area. 2.7. The exclusion of any portion of shared contingency resources included in another Balancing Authority's Regulating, Contingency, or Frequency Responsive Reserve plans. 2.8. The amount of the Balancing Authority's or Reserve Sharing Group's resources that can be reduced in response to a Large Loss of Load Event. Requirement R4 R4. Each Reserve Sharing Group or Frequency Response Sharing Group shall have a signed agreement among the participating Balancing Authorities addressing each of the following: 4.1. The minimum reserve requirement for the group 4.2. Allocation of reserves among members 4.3. The procedure for activating reserves 4.4. Reporting and record keeping processes
R3. Each Balancing Authority or Reserve Sharing Group shall	This Requirement has been moved into BAL-002-2 Requirements R1 and BAL-	BAL-002-2 Requirement R1

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	012-0 Requirement R2	Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period: • The Balancing Authority or Reserve Sharing Group returned its ACE to: o Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or o Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative. • Provided, however, that in either of the foregoing cases, if the Reportable contingency Event (individually or when combined with any previous

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods. BAL-012-0 Requirement R2 R2. Each Balancing Authority and Reserve Sharing Group shall, once each calendar year with no more that 15 calendar months between intervals, document its annual plan for Contingency Reserve used to recover from Balancing Contingency Events addressing each of the following: [Violation Risk Factor:] [Time Horizon:] 2.1. The determination of the Balancing Authority's or Reserve Sharing Group's Contingency Reserve

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		margin. 2.2. The types of resources and the portion of their capacity capable of reducing the Balancing Authority's Area Control Error in response to each of the following 2.2.1. Balancing Contingency Event 2.2.2. Events associated with Energy Emergency Alert 2, and 2.2.3. Events associated with Energy Emergency Alert 3. 2.3. The control of supply and demand resources such as generators, controllable Loads and energy storage devices. 2.4. The incorporation of energy import and export schedules by entities within the Balancing Authority Area and with other Balancing Authorities. 2.5. The characteristics: such as capabilities, constraints and volatilities, of the resources operating inside the Balancing Authority Area. 2.6. The characteristics: such as capabilities,

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		constraints and volatilities, of the Load operating inside the Balancing Authority Area. 2.7. The exclusion of any portion of shared contingency resources included in another Balancing Authority's Regulating, Contingency, or Frequency Responsive Reserve plans. 2.8. The amount of the Balancing Authority's or Reserve Sharing Group's resources that can be reduced in response to a Large Loss of Load Event.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero.	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" definition	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period: • The Balancing Authority or Reserve Sharing Group returned its ACE to: o Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.		Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or o Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative. • Provided, however, that in either of the foregoing cases, if the Reportable contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods. BAL-002-0 Requirement R4.2 to "Contingency Event Recovery

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Period" and "Contingency Event Restoration Period" definitions. Contingency Event Recovery Period A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored. A period not exceeding 15 minutes following the start of the Balancing Contingency Event.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more	This Requirement has been moved into BAL-002-2 Requirement R1 and BAL-012-0 Requirement R4	BAL-002-2 Requirement R1 Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing authority or Reserve Sharing Group can demonstrate that, within the Contingency Event

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods: R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or		Recovery Period: • The Balancing Authority or Reserve Sharing Group returned its ACE to: o Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or o Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative. • Provided, however, that in either of the foregoing cases, if the Reportable contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single contingency (MSSC), then the Balancing Authority or

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.		Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods. BAL-012-0 Requirement R4 R4. Each Reserve Sharing Group or Frequency Response Sharing Group shall have a signed agreement among the participating Balancing Authorities addressing each of the following: 4.1. The minimum reserve requirement for the group 4.2. Allocation of reserves among members 4.3. The procedure for activating reserves 4.4. Reporting and record keeping processes
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within	This Requirement has been moved into the BAL-002-2 "Contingency Event	BAL-002-2 Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
the Contingency Reserve Restoration Period for its Interconnection. R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period. R6.2. The default Contingency Reserve Restoration Period is 90 minutes.	Restoration Period" definition	the Contingency Event Recovery Period, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored. A period not exceeding 15 minutes following the start of the Balancing Contingency Event.

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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Question 7 Comments (33 Responses)

Individual
Robert Blohm
Keen Resources Asia Ltd.
No
The definition of "Pre-Reportable Contingency Event ACE Value" is written in convoluted English. It can be written simply as: "The value of ACE immediately prior to the earliest Reportable Contingency Event that occurred after the last time all previous Reportable Contingency Events' recovery periods had expired."
Yes
Yes
Yes
Yes
Individual
Joe Tarantino
Sacramento Municipal Utility Disrtict
Yes
Yes
Yes
Yes
Yes

Individual
Brendan Kirby
Consult Kirby
No
The language in the definition of “Balancing Contingency Event” under C. a. i. and ii. appears to allow deployment of contingency reserves in the case when a generator fails to come back from a maintenance outage. Or contingency reserves could be deployed if a generator is forced off line early in the day. If either of these generators was being counted on to provide energy during the upcoming peak period the system operator might conclude that this will “leave the responsible entity unable to maintain its ACE following the failure, unless it deploys Contingency Reserve.” My concern is that the contingency reserves can be deployed before there is any ACE deviation (“...not an immediate cause of an unexpected change to the responsible entity’s ACE...”). Since there is no ACE deviation there is no DCS event start time and consequently no requirement to restore reserves. There is no Contingency Event Recovery Period and no Contingency Reserve Restoration Period. Further, simply declaring that a generator has unexpectedly become unavailable and the system operator feels the system will be unable to maintain ACE without deploying contingency reserves now exempts the system from DCS accountability indefinitely because any further contingency will be greater than the Balancing Authority’s Most Severe Single Contingency. The language in the second bullet under R1 appears to grant this exemption because the first generator failure, which did not result in an ACE deviation, never started the clock that would end the Contingency Reserve Restoration Period.
Yes
No
If the Balancing Contingency Event definition is not changed to eliminate the use of contingency reserves prior to an actual event then that must be addressed here.
Yes
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst offers the following comments for consideration related to the proposed defintions: 1. Definition of Balancing Contingency Event a. RFC seeks further clarification on section C of the definition of Balancing Contingency Event. Based on the language, RFC believes this section is already covered in section A. The “Inability to start a unit...” and “Internal plant equipment problems that force the generator to be ramped down or taken offline” seems to be very similar as a “unit tripping” or a “Loss of generator Interconnection Facilities resulting in isolation of the generator from the Bulk Electric System” which is covered in section A. RFC recommends removing section C. 2. Definition of Reportable Contingency Event: a. RFC questions how the 80 percent value was determined. Is there an associated technical justification for this value? If so, can the SDT explain?
Group
PacifiCorp

Sandra Shaffer
Yes
Yes
Yes
Yes
PacifiCorp is concerned about the deletion of the highlighted language from the Applicability section of BAL-002-2. Without this language, it could be interpreted to mean that both Balancing Authorities and Reserve Sharing Groups must comply with the standard. Under BAL-002-1, Balancing Authorities may meet the requirements through participation in a Reserve Sharing Group. While this information is set forth in the Additional Compliance Section 1.4, the Federal Energy Regulatory Commission has taken the position that information set forth in the Additional Compliance Section is not part of the requirements of the standard and thus, may not be used to interpret the standard. As a result, PacifiCorp suggests including this explicitly in the Applicability or Requirements section of the standard. PacifiCorp would also propose including the other language contained in the Additional Compliance Section in the Requirements portion of the standard to ensure that it will be interpreted as part of the standard. 4. Applicability 4.1 Balancing Authority 4.2 Reserve Sharing Group (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
Individual
Greg Travis
Idaho Power Company
Yes
Yes
Yes
Yes
Yes
None
No
Individual
Michael Falvo
Independent Electricity System Operator
No
1. The term Balancing Contingency Event, Category B: we suggest changing “non-interruptible import” to “import” since a BA must be able to meet DCS requirement and recover ACE regardless of the type of import that gets curtailed or interrupted. A sudden loss to an interruptible import has the same resource deficiency impact on the importing BA. 2. The term Most Severe Single Contingency: The wording “or the greatest loss of activated Direct Control Load Management used by the Balancing Authority” gives the misconception that it is the loss of the load under the Direct Control Load Management program. Such a loss will actual result in increasing available resource in the BA area, which enhance the BA’s capability to meet firm system load and non-interruptible export obligation. We suggest to revise the wording to “or the greatest loss of capability of Direct Control Load

Management used by the Balancing Authority…” 3. Contingency Event Recovery Period: We do not agree with the proposed start time. The period should start when tie deviation exceeds the reporting threshold. Operators do not normally start implementing remedies until the threshold level is exceeded. It is not clear when the recovery period begins for Balancing Contingency Event Category C, as it may not be an immediate cause of an unexpected change to ACE with the responsible entity’s judgment also a factor. 4. Balancing Contingency Event: Category C requires clarification in order to determine the magnitude of the contingency event. For example, if a 900 MW generating unit failed to start that was to ramp to full output in 45 minutes and in the Entity’s judgment, contingency reserve is required to restore ACE, what is the magnitude of the contingency? Categories A and B are straight forward as they both relate to sudden losses, however it is unclear on how to determine magnitude for reporting purposes.
Yes
No
1. The requirement states that the BA or RSG experiencing a Reportable Contingency Event shall implement its Contingency Reserve Plan, which implies that it must be done. There could be occurrences where a Reportable Contingency Event has occurred, where ACE is restored without the need for activating contingency reserve. For example, pre-contingency ACE is positive and demand is reducing just prior to event and following the event, ACE meets requirements. Must a BA or RSG activate contingency reserve if not required? BAL-002-1 states that each BA or RSG shall activate sufficient Contingency Reserve to comply with the DCS, which implies that it is activated as required. Suggest revising to provide clarification.
Yes
Yes
There is no technical basis provided for the 500 MW reporting threshold, and its universal application across all Interconnections is not explained in the standard or the background document.
Individual
Michael Goggin
American Wind Energy Association
No
It may be efficient and desirable from a reliability standpoint to use contingency reserves under some circumstances to help accommodate the initial phase of extreme ramps in wind energy output, which would not be allowed under the standard as currently drafted. Since extreme wind events would be extremely rare (a few times per year) and short-lived (typically shorter than an hour or two in duration), such events would be highly unlikely to coincide with other demands for contingency reserves. For equity reasons it may also make sense to expand access to contingency reserves to wind plants, since contingency reserves are maintained for all users of the power system, yet under current rules wind plants use far fewer contingency reserves than other types of generation.
Yes
Yes
Yes
Yes
Group

Progress Energy
Jim Eckelkamp
No
Reportable Contingency Event should be changed to read “Any Balancing Contingency Event greater than or equal to 80 percent of the Balancing Authority’s Most Severe Single Contingency.” The 500 MW amount in the proposed definition is not necessary and will not improve Reliability of the BES. The basis or rationale for the 500 MW amount is not discussed in the background document. The proposed Pre-Reportable Contingency Event ACE Value needs to provide a specific time frame for calculating pre-event ACE instead of “immediately prior.”
No
This Standard should be combined with the proposed BAL-013 to cover all sudden ACE deviations greater than a certain magnitude occurring in one minute of less, regardless of if the event is a loss of generation, resources, or load.
No
The fourth bulleted item “Provided….” is not clearly worded in a manner that would allow for easy understanding of what is required. It is not clear when the “clock” starts and ends for a series of contingency events that exceeds the MSSC. PEC agrees with the concept that timely restoration of ACE needs to take place, even when the event exceeds the MSSC, however the required time frames must be clearly defined and understandable to System Operators and Resource Planners.
No
There is no background or rationale given for the 500 MW threshold required for a “Reportable Contingency Event.”
Should “Reporting ACE” that is a newly defined proposed term be used in place of just “ACE” in order to achieve consistency across this set of Standards proposed in this Operating Reserves project?
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
No
In order to address the proper treatment of slowly evolving generation losses, the second sentence of the definition of Contingency Event Recovery Period should be revised to read: “…The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event that occurs within the first minute in which the change in MW output exceeds the size of the applicable Reportable Contingency Event.” For the Reportable Contingency Event, the 500MW reporting threshold would be a reduction in the DCS threshold for some Balancing Authorities. This

could present a double jeopardy situation with the NPCC spinning reserve requirement determination.
No
Requirement R1 has the proper concepts, but the bullets should be rewritten for clarity. Suggested rewording: o The Balancing Authority or Reserve Sharing Group: o If its ACE was positive or equal to zero just prior to the Reportable Contingency Event returned its ACE to zero less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, Or o If its ACE was negative just prior to the Reportable Contingency Event returned its ACE to its Pre-Reportable Contingency Value less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period.
Violation Severity Levels have not been provided. The Standard does not address whether load shedding should be used if necessary to be compliant.
Individual
John Tolo
Tucson Electric Power
No
While the definitions provide some clarity, there have been no reliability issues related to the declaration of reportable events. Therefore leave the threshold at 80% of MSSC.
Yes
No
I agree with the 4th bullet, bullets 2 and 3 have verbage added that may be confusing. I prefer the existing R4.1 language. Currently there is no requirement for an Contingency Reserve Plan. If this Standard passes on its own, then that implies another compliance requirement for which there is no guidance.
No
With some modifications to R1, this Measure is acceptable.
No
Overall, the document provides clarity. However, the purpose of BAL-002-2 should be to recover from contingencies, not measure the success of a plan.
no
Individual
Kathleen Goodman
ISO New England Inc.
No

Although generally supportive of the modified Standard, we know of no known reliability concerns with the existing 80% FCL threshold on DCS and, therefore, do not understand or support the lowering to 500 MW. We would support, however, development of a Reliability Guideline, similar to what is being done for System Operator Verbal Communications, to enable reporting of smaller events (i.e. greater than 500 MW) to achieve more granular data and a larger sample set for potential future use, if deemed necessary by analysis. We would also provide a comment for the SDT to consider: although DCS compliance is important from a standpoint of ensuring adequate reserves are available and able to respond to contingencies, we do not believe that extraordinary actions (i.e. shedding of firm customer load) should be taken to comply with the DCS 15-minute recovery when the frequency and transmission system are in a secure operating space. Somehow we would appreciate it documented within BAL-002 that contingency recovery should not only place second from frequency and transmission security, but would note that striving for compliance with the DCS 15-minute recovery in some instances may actually create more harm on the system from an operating reliability perspective by having negative impact on limits or frequency.
No
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No
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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
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes

Yes
Yes
Yes – This is a long and potentially complicated requirement. There will definitely need to be a further explanation/examples included for clarification.
Yes
No
No - The current BAL-002-1 states that its purpose is to “to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance” while the draft states its purpose is “to ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority’s or Reserve Sharing Group’s Area Control Error to defined values”. The background document does not discuss the reasoning for the difference in purpose statements.
No conflicts
Utilities will start units earlier than required to ensure they are available when needed for reserve purposes. Balancing Contingency Event definition “C” would seem to allow for waiting until the unit is actually needed and then declare an event if the unit fails to start.
Group
Southern Company
Antonio Grayson
No
Southern Company does not agree with the 500MW specification in the definition of “Reportable Contingency Event”. It is unclear what the basis for this value is. The background document did not provide any technical basis for this value. Please explain why this value was chosen. Southern suggest that each interconnection have a distinctive reporting level based on frequency impact and do not agree with the 500MW value in the definition of ‘Reportable Contingency Event’. We propose that the definition of ‘Reportable Contingency Event’ be changed to ‘Reportable Balancing Contingency Event’. Southern recommends that the definition of ‘Balancing Contingency Event’ include Direct Control Load Management and be removed from the definition of MSSC. Also, as it relates to the definitions of ‘Balancing Contingency Event’ and ‘Most Severe Single Contingency’, it is unclear what constitutes an event and is ultimately considered the MSSC. To avoid any misinterpretation by the industry or compliance enforcement entities, the SDT needs to clarify what types of events should considered a MSSC. Examples: • Would a tornado causing the trip of multiple units at a site that exceeds the loss of the most severe single generating unit contingency be considered a credible contingency? • Would common scrubber, common GSU, etc. type events be considered credible contingencies in the identification of the MSSC? In general, Southern is concerned that credible but unlikely events would be construed as an MSSC for an entity and suggest the SDT to create a technical document with more clarification on this. We also suggest that “Sudden Loss” be clarified to occur within a one (1) minute time frame. We suggest changing the verbiage of the first sentence of ‘Contingency Event Recovery Period’ to read ‘A period not exceeding 15 minutes following the start of the reportable Balancing Contingency Event’. We further suggest changing the verbiage of the first sentence of ‘Contingency Event Restoration Period’ to read, ‘A period not exceeding 15 minutes following the start of the reportable Balancing Contingency Event’.
Yes
No
R1 should not require the implementation of the Contingency Reserve Plan. ACE recovery is the goal, not the implementation of the plan.
No
The Measure for the proposed Requirement requires reporting for units >80% of the largest contingency; however, the Measure does not address units >=500MW as stated in the definition of ‘Reportable Contingency Event’. Southern Company does not agree with the 500MW specification in

the definition of “Reportable Contingency Event”. It is unclear what the basis for this value is. The background document did not provide any technical basis for this value. Please explain why this value was chosen. Southern suggest that each interconnection have a distinctive reporting level based on frequency impact and do not agree with the 500MW value in the definition of ‘Reportable Contingency Event’.
No
The background document addresses carrying reserves to recover from the most severe single contingency. There seems to be no rationale or explanation for reporting events less than 80% of the MSSC. Please explain why the rationale for reporting events greater than 500 MW.
Individual
Chris Mattson
Tacoma Power
No
Tacoma Power generally agrees with the definitions as proposed. However, the use of the term “Balancing Authority” should be clarified in the definitions of MSSC and Pre-Reportable Contingency Event ACE Value. Tacoma Power suggests that the term be replaced with “Reserve Sharing Group or a Balancing Authority not in a Reserve Sharing Group.” These definitions should only apply to a Balancing Authority when the Balancing Authority is not a member of a Reserve Sharing Group.
No
Tacoma Power generally agrees with the purpose statement as proposed. However, the use of the term “Balancing Authority” should be clarified. Tacoma Power suggests that the term be replaced with “Reserve Sharing Group or a Balancing Authority not in a Reserve Sharing Group.” The purpose of this standard should only apply to a Balancing Authority when the Balancing Authority is not a member of a Reserve Sharing Group.
No
Tacoma Power generally agrees with the Requirement as proposed. However, the use of the term “Balancing Authority” should be clarified. Tacoma Power suggests that the term be replaced with “Reserve Sharing Group or a Balancing Authority not in a Reserve Sharing Group.” The Requirement should only apply to a Balancing Authority when the Balancing Authority is not a member of a Reserve Sharing Group.
No
Tacoma Power generally agrees with the Measure for the proposed Requirement as proposed. However, the use of the term “Balancing Authority” should be clarified. Tacoma Power suggests that the term be replaced with “Reserve Sharing Group or a Balancing Authority not in a Reserve Sharing Group.” The Measure for the proposed Requirement should only apply to a Balancing Authority when the Balancing Authority is not a member of a Reserve Sharing Group.
Yes
Tacoma Power does not have any concerns with the document at this time.
Tacoma Power is concerned how the proposed standard can be interpreted for application to Balancing Authorities. The proposed standard should only apply to a Balancing Authority when the Balancing Authority is not a member of a Reserve Sharing Group.
Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.
Group
LG&E and KU Services
Brent Ingebrigtson
No
Balancing Contingency Event B. Sudden Loss of Non-Interruptible Import LG&E and KU Services suggest striking the language “due to forced outage of transmission equipment.” A reliability entity can cut a tag for reasons other than a forced outage of transmission equipment (equipment OLs, contingency/stability/voltage criteria, etc.) – the sink BA experiencing the loss of the import may not

know the reason and thus not know if the loss meets the definition of a Balancing Contingency Event. It is unclear whether “non-interruptible” means firm transmission or firm power. C. Unexpected Failure of Generation to Maintain or Increase It’s wrong to assume that the failure of a generator to start or increase will negatively impact ACE or BES reliability – the start may be for testing, an early/preemptive/precautionary start or similar action that does not negatively impact ACE. Language under “C. b.” is vague, overly broad, and is prone to interpretation or selective enforcement by CEAs. LKE suggests “C” be deleted. This language could be added to “A” to cover situations where lack of generator performance negatively impacts ACE. Most Severe Single Contingency (MSSC) NERC currently does not have a definition for MSSC so this is the first attempt to draft such a definition. But this does not need to be defined since Contingency is already a NERC Glossary term. Since Contingency is already defined and the terms “single” and “most severe” are clear and unambiguous in their meaning, it is unnecessary to define MSSC. A Balancing Contingency Event (BCE) is only recognized after it occurs but the MSSC is a forward-looking/planned/forecasted/predicted value. It is not possible for an entity to predict the largest BCE that could possibly occur. The MSSC definition as drafted is too broad. The loss of Direct Control Load Management should be included in the definition of Balancing Contingency Event and not thrown into any definition of MSSC (i.e. make loss of DCLM a type of BCE). For non-interruptible export obligations – it is unclear how the source BA should know that the sink BA carries CRs to cover the export. As written, it appears that if the sink BA carries CRs then the export will not be considered as a potential MSSC for the source BA but it could be the MSSC for the sink BA. Reportable Contingency Event The NERC Glossary currently defines a “Reportable Disturbance” (vs. the proposed Reportable Contingency Event). It is unclear whether the definition of Reportable Disturbance will be deleted. To be consistent, call it a “Reportable Balancing Contingency Event”. There is no apparent reliability need to lower the reporting threshold below the current 80% of MSSC. Applying a “hard” reporting threshold like 500MW for all BAs does not seem efficient or realistic due to the wide range of BA sizes. If the SDT is aware of any reliability purpose for changing the threshold, it should make that available to the industry. Such transparency by the SDT will benefit discussions in building industry consensus. Contingency Event Recovery Period LG&E and KU Services suggest “A period not exceeding 15 minutes following the start of the Reportable Balancing Contingency Event. The start of the Reportable Balancing Contingency Event is the point in time where the first change in ACE is observed due to the event.” Otherwise Contingency Event Recovery Period is applicable to all BCEs which is inconsistent with the Purpose statement of the standard. Also, it may be difficult to ascertain exactly “where the first change in MW is observed due to the event” – the first MW change could occur several seconds or minutes prior to recognition of the occurrence of a Reportable Contingency Event. Contingency Reserve Restoration Period LG&E and KU Services suggest “A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the Amount of Contingency Reserve deployed to recover from a Reportable Balancing Contingency Event is to be restored.” Otherwise Contingency Reserve Restoration Period is applicable to all BCEs which is inconsistent with the Purpose statement of the standard. Pre-Reportable Contingency Event ACE Value LG&E and KU Services suggest: The value of ACE immediately prior to a Reportable Balancing Contingency Event when there are no previous Reportable Balancing Contingency Events for which the Contingency Event Recovery Period is not yet completed, or The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Balancing Contingency Event for which the Contingency Event Recovery Period is not yet completed.
No
R1 should not require the implementation of the CR plan – ACE recovery is the goal, not implementation of the CR plan. Standards should be “results based”. Requirements should focus on what is needed for reliability, not “how” it is achieved. Compliance with R1 should not be dependent on correct implementation of a plan. “Previous” should not be capitalized.
The language used in the definitions and the language used in R1 is confusing. The definitions and parts of R1 indicate the 15 minute ACE recovery and 90 minute CR recovery clocks are applicable to all BCEs – not just the reportables. But R1 is clearly applicable only to Reportable CEs. Consistency is needed between the terms and language used in the definitions and R1. What is the reliability

purpose for extending the data retention period out to current year plus 3 calendar years from the currently required 1 year minimum? LG&E and KU Service suggests that the SDT provide clarification on reporting requirements, and provide its reasoning for such reporting requirements
Individual
Ed Davis
Entergy Services
No
There is a concern with the definition regarding 'Contingency Event Recovery Period' and when the 15-minute clock starts if a unit is experiencing issues and has a drop in MW output but does not actually trip offline until sometime later. The way the definition is proposed is that 'The start of the Balancing Contingency Event is the point in time where the FIRST change in MW is observed due to the event'. In some instances, this may not be for some period before a unit actually trips offline (possibly after the 15 minute window) or is able to recover from another issue. Also, the EMO/SPO does not agree with the proposed definition of 'Reportable Contingency Event' as currently being drafted, particularly 'the LESSER amount of 80 percent of the Balancing Authority's Most Severe Single Contingency OR 500 MW'. We do not agree that any MW loss less than 80% of the MSSC should be considered a Reportable Contingency Event.
Group
Bonneville Power Administration
Chris Higgins
No
The definition doesn't contain the "Single" portion of MSSC. This describes any event (multiple contingencies) of any size. BPA would like to see the definition expanded to include the "Single" portion of MSSC.
Yes
No
BPA believes the first paragraph of R1 should be removed. The "shall implement its Contingency Reserve plan" is covered in another requirement, which is referring to another potential standard. What if an entity has a choice between implementing NERC's plan, or meeting DCS? BPA appreciated the addition of the last bullet.
No
BPA does not support the proposed Measure in the standard because BPA disagrees with the requirement.
No
The last sentence of the Introduction states: The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve plan. BPA believes the primary objective is to recover from contingency events for the reliability of the system, not to ensure a plan is followed.
Group
SPP Standards Review Group
Robert Rhodes
No
Balancing Contingency Event - This definition is extremely complicated and contains numerous intertwined components which make it difficult, at best, to ascertain compliance. Is there any way the

SDT could simplify or consolidate elements of this definition to make it more palatable? Further explanation could be included in the background document. In Section C., what is the generation expected to maintain or increase? Is it MW, MVAR, boiler pressure, etc.? Also in Section C.a.i., we would suggest that the item read: i. inability to start a unit (for reasons other than lack of fuel) the Responsible Entity planned to bring online at that time, or Reportable Contingency Event – We have some concern over the addition of the 500 MW reporting criteria in this definition. Within SPP this raises the risk level of the Reserve Sharing Group considerably. What was the basis for including this criteria? Such an explanation was missing in the background document. Could the SDT please share their thinking on this issue? Within SPP, we have an established criteria whereby contingencies of 600 MW or greater are reviewed for DCS compliance whereas our official DCS compliance reporting criteria is approximately 1,000 MW. If such a requirement is needed and the SDT can share the reasoning behind that requirement, we would propose to set the threshold at 600 MW.
Yes
No
We are unsure of exactly what the reporting requirements are for R1. In the existing BAL-002-1, it is pretty clearly laid out, although spread out throughout the standard, what the BA or RSG must report to demonstrate compliance. It's contained in M1 and Section D.1.5. The existing BAL-002-1 also offers two options for reporting compliance for an RSG – one from the RSG perspective and one from the RSG participants taken individually. R1 implies that only the RSG as a group is to be reported. If this is the case, the SDT could clarify this by including a term Reserve Sharing Group ACE, and its definition, in the standard.
No
Please see our comment regarding reporting requirements in Question 3.
No
The document only contains a brief introductory paragraph, the requirement itself and another brief paragraph consisting of only a few lines of background and rationale material. The document contains no helpful information that provides any further clarity to the standard or the definitions used in the standard. Additional information on the definitions is disparately needed as some of the definitions are extremely complicated.
Not aware of conflicts.
No.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
No
The definition of Balancing Contingency event seems overly complicated and it is not clear it is even needed. It appears to be an attempt to provide more precision over what constitutes a contingency that may be subject to DCS. However, it does not address all situations and could actually result in confusion over whether a particular situation is included as a result. For example, would a run back of a generator over a two minute period constitute a Balancing Contingency Event? Traditionally, these would be considered contingencies and subject to DCS if they meet the reportable event threshold. However, because the definition is so precise and does not specifically mention run backs, we are left confused over whether or not they are considered. The definition of Most Severe Single Contingency (MSSC) is too complicated. We suggest it should be kept very simple. It should be no more complicated than: "MSSC: The single most credible contingency that would result in the greatest resource loss." Even though there is a FERC directive to include Demand Side Management (DSM), the definition does not specifically have to reference it as long as the generic "resource" is used. The ultimate filing to FERC could simply explain that resource is intended to cover any type of resource including DSM. This explanation could also be included in an application guidelines section along with an explanation of the MSSC. We disagree with the definition of Reportable Contingency Event. First, it is not clear why the current Reportable Event definition is not satisfactory and if it is not, it is not clear why it is not being revised rather than creating a new term. The implementation plan does not even consider retiring the Reportable Event definition. Second, no basis is provided for the 500 MW threshold. Without a sound technical basis, it appears to be arbitrary. This is particularly troubling

considering that a BA or RSG can reduce the 80 percent threshold per section 1.4 of the standard. We disagree with the definition of Contingency Event Recovery Period. It states that the period starts at the point in time where the first change in MW is observed. For a generation runback over a period of a few minutes, this is problematic and significantly shortens the time period to recover from the contingency. It should start immediately after the final MWs of the contingency are lost. The definition of Contingency Reserve Restoration Period is not needed and provides no additional clarity. It is used only once in the standard in the second bullet under Requirement R1. The bullet would be clearer if it directly stated that for any contingencies with an aggregate total that exceeds the MSSC that occur within 90 minutes of the first contingency, the BA or RSG only has to recover for the loss of the MSSC. The bullet correctly assumes that the BA or RSG will try to recover its contingency reserve in less than 90 minutes. However, it is not necessary to refer to the Contingency Reserve Restoration Period to cover this shorter period. The BA will either take the full 90 minutes to recover its contingency reserve or the BA will recover the contingency reserve in less than 90 minutes. If a contingency occurs before contingency reserve is fully recovered, the BA may have to use its emergency procedures which are required in the EOP standards. If the BA has recovered the full amount of its contingency reserve before the next contingency, it will be able to recover ACE. Thus, reliability is preserved either way and the requirement is simpler.
Yes
No
We disagree with the implied requirement to have a contingency reserve plan. No such plan was required in the existing standard and no justification has been provided for its need. There are enough resource contingencies that actual demonstration of implementation of contingency reserve should be sufficient.
No
It seems the only way to verify that ACE was recovered is to have ACE data available. Thus, we would expect to see ACE in the measurement.
No
There is essentially a single paragraph of explanation in the background document. The rest is either the requirement or an introduction. Significantly more background needs to be provided to explain such dramatic changes to this standard. For example, why does the document imply a requirement to have contingency reserve plan? No such requirement existed in the past. The existing standard was fairly clear. Only a few refinements were necessary to the existing standard to address outstanding issues.
In general, we do not understand the wholesale rewrite of this standard and the indirect and implicit requirement to have a contingency reserve plan. We further do not understand why some of the requirements were modified and moved to BAL-012-1 and BAL-013-1. One key issue really needed to be addressed in this standard regarding clarifying within the requirement that a BA or RSG could not be held in violation of the standard for a contingency that exceeds the MSSC. We disagree with the data retention requirements of up to four years. First, it raises the bar without justification from the current standard which only requires one year. Second, they are 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 “current year, plus three calendar years” exceeds the compliance audit period of three years for the BA. Third, NERC already requires quarterly data reports for DCS and will likely continue to require similar reports even with this new standard. Thus, NERC can retain these reports for the four years if they need them. The implementation plan proposes to retire both BAL-002-0 and BAL-002-1. BAL-002-0 has already been retired on March 31, 2012.
Individual
Don Jones
Texas Reliability Entity
No
The MSSC should not be limited to the greatest loss of generation output; it may also be due to the loss of an import tie line. Even with the definition of “Balancing Contingency Event” including sudden

loss of non-interruptible import, the inclusion of “of generation output” phrase in the MSSC definition could be misinterpreted. Suggest referencing Subsection A, B, or C of the Balancing Contingency Event definition. Should there be any mention of Reserve Sharing Group obligations in the MSSC and Reportable Contingency Event definitions (implied in Requirement 1 but not explicit in the definitions)? Should the “Contingency Event Recovery Period” and “Contingency Reserve Restoration Period” apply to all Balancing Contingency Events or only to Reportable Contingency Events, in order to be consistent with Requirement R1? There is an existing definition for “Contingency Reserve” which may need to be modified (refers to DCS standard and RRO). There is an existing definition for “Disturbance Control Standard” which may need to be modified or deleted. There are existing definitions for “Operating Reserve-Spinning” and ”Operating Reserve-Supplemental” which may need to be modified (refer to “contingency event” and “Disturbance Recovery Period”).
No
The purpose statement does not match the title or the intent of the Standard. Need to ensure consistency between the use of “Reportable Contingency Event” and “Balancing Contingency Event.”
Yes
We agree with the intent of last bulleted paragraph of R1 to require a BA or RSG to carry enough contingency reserves for its MSSC, however the wording is confusing.
Yes
There should also be a requirement for compliance with the Contingency Reserve Restoration Period. None is explicitly stated. R1 appears to only cover the Contingency Event Recovery Period as the BA/RSG implements its Contingency Reserve plan.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
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
Yes
No
No
South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Individual
Karen Webb
City of Tallahassee
No
1. The City of Tallahassee (TAL) disagrees with the definition for Reportable Contingency Event, as it does not provide the latitude to modify the minimum threshold as is discussed in section D.1.4., Additional Compliance Information, which states a BA or RSG can reduce the 80% threshold. 2. TAL seeks clarification on the end-time for the Contingency Event Recovery Period. Without a defined end-time, entities would presumably define the end-time individually, including up to the maximum 15 minute period to restore ACE to the Pre-Contingency Event ACE Value. 3. TAL disagrees with the

proposed definition of the Most Severe Single Contingency, due to the inclusion of the loss of load scenario. TAL believes loss of load can be measured in the proposed BAL-001-1, R2 30-minute criterion.
Yes
Yes
Yes
No
TAL seeks additional information or examples in the background document to understand what events require evidence of what level of recovery when combined with the Disturbance Recovery Periods.
1. 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. 2. Additional Compliance Information: This section states that a BA or RSG may optionally reduce the 80% threshold, but does not address reduction of the 500MW threshold. TAL is unclear as to whether this was an intentional omission or if there is justification to only having the minimum threshold of 500MW.
Group
Associated Electric Cooperative, Inc., JRO00088
David Dockery
No
Reportable Contingency Event definition, and others as noted below: Remove: “or 500 MW” then realign all other definitions accordingly, to remove loss of load contingency references Rationale: AECI was encouraged to see that our industry cited a load-loss value other than the too-often cited 300 MW “tell DOE, so they won’t get caught flat-footed before our President or Congress?”, but we were equally disappointed to discover there was no technical reliability-related justification for the 500 MW value drafted within the supporting “BAL-002-2_Background_Document_Clean_20120601” document. Because this 500 MW threshold is not technically supported and it stands in confusing conflict with the 300 MW DOE reporting threshold, it should be removed. (SEE AECI rationale posted with BAL-013-1 Question 1, regarding Large Loss of Load Event definition, pertaining to a PNNL technical study of the Western Interconnection system.)
Yes
No
BAL-002-2 R1 changes: Remove: “so that the Balancing Authority or…”, ie remove everything that follows within this requirement’s wording. Rationale: While Contingency Reserve plans are designed to accomplish the bulleted items within this Requirement 1, there is no guarantee of their success in every possible circumstance. Having these extra words assuring each plan’s achievement of other requirements, only serves to expose the industry to double-jeopardy where a plan failed to cover unimagined circumstances.
Yes
Wisely worded.
No
The SDT failed to technically justify their 500 MW load-related threshold.
No
Since the SDT changed data-retention from 1 to 3 years, the background document should provide insight into that change. If the change is for audit-period, then those could become longer and so a wording change should provide the necessary flexibility to cover that possibility.
Group

ISOs Standards Review Committee
Terry Bilke
No
1) The term Balancing Contingency Event is overly complex and pulls in things never intended in DCS (failure of a generator to start or move). The only problem with today's definition is that due to differences between beta and Bias Setting, ACE magnitude does not equate to contingency size. 2) The term Most Severe Single Contingency (MSSC) is now complicated in that it is nested with the Contingency Event term. There is no need to change the existing definition. 3) We disagree with the definition of Contingency Event Recovery Period. The period should start when tie deviation exceeds the reporting threshold. Operators aren't psychic and don't know if a runback or other partial event will turn into a reportable event. 4) The term Balancing Contingency Event, Category B: we suggest changing "non-interruptible import" to "import" since a BA must be able to meet DCS requirement and recover ACE regardless of the type of import that gets curtailed or interrupted. A sudden loss to an interruptible import has the same resource deficiency impact on the importing BA. 5) The term Most Severe Single Contingency: The wording "or the greatest loss of activated Direct Control Load Management used by the Balancing Authority" gives the misconception that it is the loss of the load under the Direct Control Load Management program. Such a loss will actual result in increasing available resource in the BA area, which enhance the BA's capability to meet firm system load and non-interruptible export obligation. We suggest to revise the wording to "or the greatest loss of capability of Direct Control Load Management used by the Balancing Authority…"
No
1) If the proposed BAL-001 BAAL requirement is approved, there is no need for BAL-002. 2) It should be noted that BAs do not always use their Contingency Reserve service to respond to events. The purpose would be better stated if it stated "To ensure the Balancing Authority or Reserve Sharing Group balance resources and demand to be within defined values (subject to applicable limits) following a Reportable Contingency Event.."
No
1) The requirement is fine when looking at BAL-002 in isolation. If the proposed BAL-001 BAAL requirement is approved, there is no need for BAL-002. 2) While avoiding defining what constitutes a contingency reserve policy, the drafting team has created a second issue as exactly what constitutes a Contingency Reserve Plan? Since it is not defined the Industry is at risk to subjective evaluations of any developed plan. 3) The compliance section of the standard should provide guidance on evaluating fixed RSGs and dynamically allocated RSGs.
Yes
Yes
1) The 500 MW reporting threshold appears arbitrary, particularly when you're using the same size for all Interconnections. 2) Ultimately, if the BAL-001 BAAL requirement were approved, BAL-002 is a redundant standard and should be retired. While the FERC made directives on BAL-002, BAAL is an equally effective alternative standard that is easier to administer and does not need all the specially proposed definitions.
Group
MISO Standards Collaborators
Marie Knox
No
• The term Balancing Contingency Event is overly complex, overly broad, and ambiguous. MISO notes that, as written, the proposed term would require reporting for Bulk Electric System (BES) issues never intended to be tracked as reportable events, i.e., failure of a generator to start or move. Further, MISO notes that the currently used term Disturbance and its definition could easily be modified to address the fact that ACE magnitude is not easily correlated to contingency size. MISO also notes that, as Balancing Contingency Event is replacing Disturbance and Reportable Contingency Event is replacing Reportable Disturbance, the introduction of these terms could result in

inconsistencies and ambiguities with Registered Entities' obligations under other Reliability Standards where these terms are utilized, e.g., BAL-003, EOP-004, EOP-005, EOP-006, IRO-005, etc. • The determination of a Balancing Authority's Most Severe Single Contingency (MSSC) is now complicated by the nesting of the term Balancing Contingency Event. The nesting of the Balancing Contingency Event into the definition and determination of a Balancing Authority's MSSC limits a Balancing Authority's ability to utilize its Subject Matter Expertise and Engineering Judgment to determine its MSSC. This appears unnecessary and would likely not result in any benefit to the reliability of the Bulk Electric System as Balancing Authorities should be free to utilize its Subject Matter Expertise and Engineering Judgment to determine its MSSC. The 500 MW reporting threshold appears arbitrary considering that each Interconnection has different and variable characteristics that determine the threshold of impact at which a Disturbance would be sufficient to necessitate reporting. Furthermore, for large BAs or organized markets, this requirement doesn't add any reliability enhancement or benefit. Specifically, MISO calculates a set of Security Constrained Economic Dispatch (SCED) generator setpoints every 5 minutes. If a 500 - 600 MW generator trips, MISO can, under most circumstances, simply calculate and distribute a new set of generator setpoints. This system allows the entire fleet of generation resources within the MISO BA to respond to generation losses and events using normal operating procedures, replacing the lost generation within 5 - 10 minutes from the time of the initial loss without requiring the initiation of emergency or abnormal operating procedures or processes. Further, the MISO BA is able to respond to such generation losses while retaining its ability to respond to major disturbances using its contingency reserves, i.e., the use of the SCED system will, under most circumstances, preempt the need to tap into contingency reserves. Accordingly, to treat these relatively small generation losses as Disturbance Control Standard (DCS) events requiring the deployment of contingency reserves may actually pose additional risk to the BES as contingency reserves would be deployed more often and unnecessarily. Further, such treatment would also require the use of abnormal or emergency operating procedures rather than utilizing the normal dispatch functions available to many system operators. Finally, MISO respectfully suggests that the administrative efforts associated with the DCS reporting required could require large BAs or organized markets to hire additional personnel simply to track these relatively small losses with no attendant or associated benefit to the reliability of the BES.
No
MISO reiterates that, if the proposed BAL-001 BAAL requirement is approved, there is no need for BAL-002. IF the BARC SDT disagrees, MISO proposes that the purpose should be revised to remove the new term, Reportable Contingency Event.
No
MISO reiterates that, if the proposed BAL-001 BAAL requirement is approved, there is no need for BAL-002. IF the BARC SDT disagrees, MISO proposes that R1 should be revised to remove the new terms upon which MISO provided comment above, specifically Balancing Contingency Event, Reportable Contingency Event, MSSC, Contingency Event Recovery Period, and Pre-Reportable Contingency Event ACE Value.
Yes
Yes
MISO notes the use of cross-references and similar terms among and between Reliability Standards. Accordingly, terms and concepts previously utilized in BAL-002-1 that have been replaced, modified, or re-defined in BAL-002-2 may impact other Reliability Standards such as BAL-003, EOP-004, EOP-005, EOP-006, IRO-005, etc. 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, modified, or replaced in BAL-002-2, a cross-referenced or closely related standard or requirement could be impacted by the modification to BAL-002-2. For example, EOP-004 governs Disturbance Reporting. The term Disturbance was once utilized in BAL-002-2 and is now replaced with Balancing Contingency Event. Do these reliability standards correlate? Should they? Hence, MISO notes to the BARC SDT that the creation of a new glossary definition could result in ambiguity regarding required performance outcomes and obligations where a previously defined term had been used and is maintained in cross-referenced or closely related standards. For example, several Reliability Standards refer to and use Disturbance. It is unclear

whether this performance obligation remains tied only to events meeting the definition of a Disturbance or whether they should now also apply to a Balancing Contingency Event. MISO respectfully suggests that the BARC SDT perform a comprehensive review of BAL-002-2's impact on cross-referenced or closely related Reliability Standards prior to implementation.
Individual
Nicholas L. Hall
Constellation Energy Control and Dispatch, LLC
No
The term "Sudden Loss" has no time-reference, which creates confusion and potentially broad interpretation when discussing Non-Interruptible Imports. Would a "Sudden Loss" of a schedule be one that is curtailed 10 minutes ahead of its scheduled start, five minutes from the current time, or instantaneously? Without a defined measurement for "Sudden Loss," Balancing Authorities are subject to a recovery standard which cannot be known ahead of time, creating an unreasonable burden for recovery. Part c of the definition for a Sudden Loss of Generation needs further clarification on when normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses, and whether they are not for consideration under this definition. The phrase "may not be subject" creates significant uncertainty for determining when, and if, a loss of generation that is the result of the normal, recurring characteristics of a unit would be considered under the definition, and therefore held to recovery under the requirements contained in this standard. The definition for Unexpected Failure of Generation to Maintain or Increase brings significant uncertainty to the process of Contingency Event Recovery, as it fails to clarify the timeframe in which a failure of a unit to start would impact a responsible entity such that it is unable to maintain its ACE. If, for example, a unit slated for startup several hours in the future fails to start, well ahead of the timeframe in which it would be needed for maintaining ACE, does that constitute a Reportable Event under this definition? If so, does the event timing (i.e. 15 minute recovery period) begin with the discovery of the unit's inability to startup, or does it begin when the lack of that unit impacts the entities ACE equal to or greater than 80% of its MSSC? Also, the reference to the inability to maintain ACE following failure does not provide any boundaries, indicating that an inability to maintain ACE at zero could result in the consideration of a failed startup as a balancing contingency event. The definition of MSSC seems to exclude consideration of non-interruptible imports, which are clearly considered in other portions of the standard. If loss of firm imports can be counted as Balancing Contingency Event in certain circumstances, what would this imply for Load Only Balancing Authorities with no internal generation? Since they cannot experience a loss of generation, how would the MSSC determination be applied to determine if a Balancing Contingency Event qualifies as a Reportable Contingency Event? The Contingency Event Recovery Period needs to include clarification on the "Start of the Balancing Contingency Event," particularly for instances in which the event is triggered either by interruption of a firm schedule, or by an Unexpected Failure of Generation to Maintain or Increase that does not have immediate or unexpected impact on an entity's ACE. Given that both of the events mentioned in this comment can play out over significant time periods (ramp time of a curtailment may be well into the future, and impact of a failed start may not be seen in actual ACE for a similarly lengthy period of time), would the start of the 15 minute recovery period be triggered from the actual event, or the point at which it impacted the entity's ACE by the lesser of 80% of MSSC or 500 MW? Similar concerns on timing, as indicated above, exist for Contingency Reserve Restoration Period and Pre-Reportable Contingency Event ACE Value. Both of these measures rely on a clear understanding of the start of the event, and the definitions as written are vague in certain instances, as mentioned. Also, clarity needs to be provided on what is meant by "ACE immediately prior," in general. Does this intend that the individual scan of ACE immediately preceding the start of the event be used, or the clock minute average ACE prior? This has been an ongoing source of vagary in DCS standards, and warrants clarification.
No
Given that the standard proposes the inclusion of events with the expectation of future impact to ACE, not actual current impact, this purpose statement seems incomplete and misleading.
No
The precedent of exclusion of simultaneous events that exceed the MSSC has long acknowledged that industry planning for N-1 contingencies is adequate and reasonable. The extension of compliance

obligations under this standard to events in excess of MSSC represents an unreasonable burden. While we acknowledge that there is also a precedent of compliance burden to carry reserves sufficient to replace MSSC, the specific extension of compliance obligation to recover within 15 minutes from such events does not allow for the understanding that unforeseen and extreme circumstances can impact an entity's ability to recover even to within its MSSC. As a simple example, take a complete failure of the BES into consideration, and it is clear that an obligation to recover MSSC for a loss in excess can represent an unreasonable burden.
Yes
No
As indicated in comments related to definitions, the standard as drafted inserts significant uncertainty as to evaluation and timing of Balancing Contingency Events.
Individual
Patricia Robertson
BC Hydro
No
1.Balancing Contingency Event: a.Point A.c. is not clear and can be subject to interpretation; b. The change to ACE is not required to be "immediate" but point C.b. implies that it should be in all cases except C.b.; 2. MSSC: The "Single" portion of this term is not clearly defined here. The definition implies this is the "Most Severe Balancing Contingency Event" which can be any event whether it's cause by the loss of a single element or multiple elements simultaneously? 3.Reportable Contingency Event: a.This is defined only for Balancing Authority, not for Reserve Sharing Group; b.Why 500 MW for all Interconnections which are of different sizes? Is there a technical basis for this amount?
Yes
No
a. This is a 2-in-1 Requirement. The implementation of the CR plan should not be included here as it is referred to another standard; b.The "sum of the magnitudes" is not clearly defined. Is it measured by the change in ACE or by the MW loss? c.BCH appreciates the clarification provided in the last bullet (MSSC).
No
BCH does not agree with the Requirement R1 as written and therefore does not agree with the Measure.
No
The Introduction of the Background Document states: The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve plan. BC Hydro believes the primary objective is to ensure the deployment of sufficient Contingency Reserve to recover from Generation loss events.
BC Hydro is not aware of any conflicts.
The unique situation where the output of a Jointly Owned Unit can be divided among multiple Balancing Authorities such that the ACE change per individual BA may not be significant but the impact of the loss of the unit may be significant to the BES should be recognized and addressed in this standard. Currently, there is no requirement for each BA to recover its ACE in such situation.
Individual
Jay Campbell
NV Energy
Yes
Yes

Yes
Yes
Yes
The background document mainly re-states the standard and adds little to understanding.
No.
No.
Individual
Laura Lee
Duke Energy
No
Duke Energy does not agree with including “or 500 MW” within the definition of “Reportable Contingency Event”. The impact of that amount of loss on the Eastern Interconnection frequency is negligible and not a reliability issue. The definition of “Balancing Contingency Event” is too broad and long. It is stated as any single event described in Subsections A, B, or C below, or any series of such otherwise single events, with each separated from the next by less than one minute. Using the phrase “or any series of such otherwise single events” leaves too much room for interpretation as to what is applicable and what is not. For many of the circumstances described, there may not be a clear threshold at times where the operator would recognize that the 15-minute clock has been triggered similar to a traditional unit loss. Upon implementation of the Balancing Authority ACE Limit (“BAAL”), the Interconnections will be operating to a real-time Standard designed to support the reliability operation of the Interconnection in consideration of the Interconnection frequency, which will catch all of the circumstances described if the resulting imbalance causes the Balancing Authority to exceed its BAAL. Duke Energy believes that the DCS should be focused upon a specific set of contingencies, similar to today, that clearly define for the operator when the measure is applicable. Please see other comments provided under Question 7. SDT may consider two separate definitions for “Pre-Reportable Contingency Event ACE Value” to avoid confusion. Having two definitions for one term creates ambiguity. The SDT could consider having a separate definition for Balancing Contingency Event and for each event. For example, “Sudden Loss of Generation” could state something like: A balancing contingency event characterized by unit tripping, loss of generator interconnection Facilities… etc.
No
As it is possible that restoring ACE to a pre-contingency state may not require implementation of Contingency Reserves, Duke Energy would suggest striking “utilizes its Contingency Reserves”, as the standard should not dictate what resources are utilized by the Balancing Authority to be compliant.
Yes
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 DCS measure. In Duke Energy’s opinion, the inability of Balancing Authority to meet the 15-minute DCS compliance threshold does not in itself represent a reliability issue. Under what circumstances, if any, should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to the Disturbance Control Standard? We would appreciate the drafting team’s perspective on this point.
Upon implementation of the Balancing Authority ACE Limit (“BAAL”), the Interconnections will be operating to a real-time Standard designed to support reliable operation and maintain Interconnection frequency within predefined limits. The merit in also having DCS in place is that it will continue to reinforce the discipline and situational awareness provided by having a Standard focused upon the Balancing Authority with the contingent loss of a resource (based on a clear and well-established criteria) being the “first responder” to that event while other Balancing Authorities at that time may be assessing their own impact on Interconnection frequency under the BAAL. However, Duke Energy is concerned with some of the revisions proposed in BAL-002-2. The clear and well-established criteria

of what triggers the DCS event has been blurred in the proposed revisions which leave far too much up to the interpretation of after-the-fact compliance scrutiny. The criteria for what applies as a DCS event must be clear – our operators have to have unquestionable guidance on this matter. BAAL will catch all load and generation nuances on the system affecting operation as reflected in the ACE; in our opinion, the criteria for DCS can remain focused on what's needed to test the Balancing Authority's capability to respond to the loss of a resource – setting a reporting threshold at 80% or greater of the MSSC in most cases has worked well for that purpose and Duke Energy would support maintaining that criteria. Duke Energy is also concerned that the current treatment of DCS non-compliance appears to be driving some Balancing Authorities to consider actions up to and including the shedding of firm load in order to be compliant. Is it the intent of the standard drafting team that the Balancing Authority take all action, up to and including the shedding of firm load, in order to never exceed the 15-minute DCS compliance limit? According to the the background document, R1 "is intended to eliminate the ambiguities and questions associated with the existing standard. In addition it allows BAs and RSGs to have [a] clear way to show compliance and support the Interconnections to full extent of MSSC" but there is no explanation as to what the ambiguities are in the background document or in the mapping document. There is a typo: "a" is missing in sentence above from background document. Also, according to the Background Information for Quality Reviews, the applicability section of the standard should indentify all of the functional entities assigned responsibility for one or more requirements in the standard. However, according the functional model the Reserve Sharing Group is not a functional entity. The glossary defines it as, "a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group..."If the Functional Model is followed strictly, the Reserve Sharing Group should not be in the applicability section. There are no VRFs, Time Horizons, or VSLs for R1 in the standard and no explanation as to why they are missing. The Additional Compliance Information section in the standard, does not match up with the language in the Mapping Document. The standard has a chart for four Requirements but there is only one requirement (R1) in the standard. Also the mapping document indicates that the standard should have two requirements (R1 and R2). In the Compliance Enforcement Authority Section the language does not mirror the default language Background Information for Quality Reviews.
Individual
Alice Ireland
Xcel Energy
No
There are six terms defined here although the first term is not in bold. Xcel Energy assumes that the six definitions presented above are part of the drafting team's effort and is commenting on all six. The definitions and requirement needs clarity as to which entity, the BA or RSG, is required to do something. In the definition of MSSC, it states the BA but the Requirement states it is the BA or RSG. If the MSSC is defined only for the BA, what is the MSSC for a RSG and what is a Balancing Contingency Event for the RSG since by definition it has not MSSC? Xcel Energy recommends that the definition for MSSC be expanded to address the RSG MSSC. Xcel Energy feels that several of these definitions need further clarification, especially Reportable Contingency Event, Contingency Event Recovery Period, Contingency Reserve Restoration Period, Balancing Contingency Event and Pre-Reportable Contingency Event ACE Value. More detail follows. In the definition of Contingency Reserve Restoration Period there is an error. An entity need only recover to the level of its MSSC at that time, not recover the amount used. As an example, an entity has two units, its MSSC of 1,000 MWs and an 800 MW unit. During an event where the 1,000 MW unit is lost, the BA/RSG would have to restore 1,000 MWs of reserve under the proposed definition even though its MSSC at this point is only 800 MWS. The drafting team must address this discrepancy. Balancing Contingency Event It is unclear whether the drafting team believes that this definition would prohibit the activation of contingency reserves due to the unexpected loss of wind generation. The wording of the definition "Balancing Contingency Event" could be interpreted to prohibit the activation of contingency reserves due to the unexpected loss or an unexpected increase of the wind driving wind generators. With the increased levels of wind generation seen in the industry today, it is unreasonable to prohibit activation of contingency reserves for what at times may constitute over 50 percent of a Balancing Authority's generation resources serving its loads. The drafting team must either clarify that activations may be for any resource or justify a position to the contrary. Additionally, the drafting team must justify why

there is a limit on activations for the loss of an import only in the event that the transmission system experiences a forced outage. It has been Xcel Energy's experience that the underlying cause of most curtailments of transactions is unknown to the sink Balancing Authority until after the fact if the curtailment is initiated by another entity. It also appears under this definition that the drafting team is using a defined term "Non-Interruptible Import" which is not found in the current version of the NERC Glossary. If the drafting team continues with this unsupported position, it must at least define what it means by "Non-Interruptible Import" since under the standards, a BA or TOP can take action to address a reliability problem, which can include curtailing any schedule for any reason, not just the forced outage of a transmission system element. As currently drafted, it is unclear when a receiving BA can or cannot activate reserves. Finally, under this definition, it would appear that the drafting team is intending to limit the activation of contingency reserves only for the loss of resources considered "firm" without defining what is or is not "firm". As an example, if a PSE associated with a Balancing Authority is buying the output of a 600 MW generator facility located in a different BA under WSPP Schedule B (Unit Commitment) and that interchange transaction is cut, is that a Balancing Contingency Event? As currently structured, only the loss of some resources would be events under this standard. That would appear to leave a very large hole that could be exploited by industry participants if the structure is not significantly improved. The drafting team must provide support for the concept that only "firm" resources can be supported by contingency reserves since the loss of any resource can cause an entity's ACE to change unexpectedly. Reportable Contingency Event The term Reportable Contingency Event should be limited to an entity's Most Severe Single Contingency. The recommended definition would be "Any Balancing Contingency Event between the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW and the Balancing Authority's Most Severe Single Contingency. An Event greater than the Balancing Authority's Most Severe Single Contingency is not a Reportable Contingency Event." This definition would provide clarity on the size of event that is intended to be addressed by the standard and will allow for reasonable planning on the part of industry participants for issues considered part of normal operations of a Balancing Authority. Additionally, the drafting team needs to further justify the use of 500 MW loss or try to set this up in relation to the size of the BA/RSG. The term Most Severe Single Contingency is not linked to a single point of failure/element. This needs to be addressed. As written, it could be argued that the loss of two units within a short time period is by definition the MSSC, rather than a double contingency. It is also not clear why the drafting team has included the loss of Direct Load Control Management in the definition. The drafting team needs to provide justification for including only this portion of load side resources and excluding others such as Demand Response, Demand Side Management, Interruptible Load, include all forms of loss of control of any activated or preferably remove this concept from the definition.
No
The language of the requirement states that the BA/RSG must implement its plan. However, implementation of a Contingency Reserve plan does not mean that an entity will meet the performance requirement to restore ACE to any level. As currently worded, it is unclear if an entity were to meet the performance requirement by utilizing a resource not shown in the plan has met the requirement or not. If there is a requirement to implement a plan, it should be separated from the requirement to perform any other action as well as address the issue of use of a resource not included in the plan. It is unclear why ACE must be returned to zero (or the pre-disturbance ACE if less than zero) when the proposed BAL-001 standard states that operation within a wide range is reasonable assuming frequency is near 60 Hz. In other words, if a BA is within the allowed operating range with an ACE of -300 under BAL-001-1, why is recovery required to be to zero? As an example, a moderate-sized BA is operating with a positive 200 ACE prior to the event when it experiences the loss of a 500 MW unit, causing its ACE to drop to a negative 300. Assuming frequency is near 60 hertz, a negative 300 ACE may be well within the boundaries established by the proposed BAL-001-1. Why does an entity need to activate reserves to drive its ACE back to zero when its ACE is within the acceptable operating range established under BAL-001-1? As currently structured, the operator must call on the contingency reserves to drive the ACE up and then would make a reasonable decision to end the use of the contingency reserves as soon as the ACE hits zero, allowing the reserves to back off and therefore be restored while the ACE drops back to negative 300. It appears that the drafting team needs to more clearly align the requirements in these two standards. To be clear, Xcel Energy support moving from CPS2 to the RBC and believes this standard needs to recognize the changes

brought about by that modification. A more appropriate level of requirement would be that the BA move back within the RBC limits within a specified time frame, such as 15 minutes. Finally, Xcel Energy believes this requirement would be better within a single standard with the requirements of BAL-001 and BAL-013. Finally, a requirement to get ACE to a specific level, regardless of any BES limit being exceeded is unreasonable an illadvised. Also there needs to be a descriptor of how the RSG can demonstrate recovery (i.e. a combined ACE, or can each BA in the RSG show non-coincidental recovery)?
No
The wording of the measure is reasonable but the result is not due to the wording in the requirement. If the drafting team addresses our concerns with the requirement, the language in the measurement is reasonable. If the drafting team does not change the requirement to address Xcel Energy's concerns, then the measurement needs to be clearer as to what constitutes implementation of the plan and not just performance.
No
There is no discussion related to the proposed definitions. Without any discussion of these very important items, the background document fails to provide sufficient support for the standard.
None known at this time.
It is unclear why the Implementation plan mentions retiring BAL-002-0. That standard is no longer included in the NERC standards documentation and is shown as inactive effective 3/31/2012. Xcel Energy also reiterates its concern with the concept of multiple standards with requirements that have a high level of interaction. It is better to have multiple requirements under a single standard and for that reason, Xcel Energy recommends that the drafting team move all requirements in BAL-001, 002 and 013 (to the extent they move forward) into a single standard.
Group
Western Electricity Coordinating Council
Steve Rueckert
No
1. Balancing Contingency Event – Item C is part of regulating reserve; the definition is very wordy. 2. Most Severe Single Contingency a) this definition should be applicable to both BA and RSG. b) The phrase" greatest loss of activated DCLM" is confusing. If the intent is to refer to the return of DCLM then WECC recommends that it be changed to "unexpected reactivation of DCLM". If it is intended to refer to an amount of DCLM no longer being available to activate, did the SDT consider "Loss of or sudden reactivation of DCLM?" c) The definition of MSSC does not refer to a single event. As written multiple Balancing Contingency Events could be MSSC. 3. Reportable Contingency Event: The definition should include RSG. Is a BA's RCE an RCE for the Reserve Sharing Group in which the BA resides? Is 80% of a BA's MSSC reportable if it is less than 80% of the RSG's MSSC? 4. Contingency Reserve Restoration Period: the proposed standard removes the requirement to restore the reserves. The last part of the definition should be deleted, "during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored", otherwise, it appears to be an attempt to put a requirement into a definition.
No
1. As written the requirement is not easy to comprehend. The requirement needs to be simplified in language and maybe provide some examples in an attachment or background document 2. The requirement should be to meet the ACE recovery within 15 minute not to implement the Contingency Reserve (CR) plan or the two should be separate requirements. As written, if a BA met the 15 minute recovery requirement but used a resource not in its CR plan it could be a violation of the requirement. 3. The SDT needs to clarify how a RSG can demonstrate ACE recovery whether its recovery of combined ACE of all BAs in the RSG or if its recovery of individual ACEs for BAs in the RSG.
No

There is no discussion related to the proposed definitions. Without any discussion of these very important items, the background document fails to provide sufficient support for the standard. The document also states it establishes a ceiling for the Contingency Reserve . It's not clear where the ceiling is established in the standard.
Order 693 directed NERC to inlcude a requirement that explicity explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves. This does not appear to have been included in the proposed standard or definitions.
Rather than a separate standard, BAL-013, did the SDT consider including the single requirement of BAL-013 in BAL-002?

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Contingency Reserve for Recovery from a Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Contingency Reserve for Recovery from a Contingency Event. Comments must be submitted using 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.

Background Information:
Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve Plan.

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 five new terms to be used with this standard.**

Balancing Contingency Event:

Any single event described in subsections (A), (B), or (C) below, or any series of such otherwise single events with each separated from the next by less than one minute.

A. Sudden Loss of Generation:
   a. Due to
      i. unit tripping,
      ii. loss of generator interconnection facilities resulting in isolation of the generator from the Bulk Electric System or from the Responsible Entity's electric system, or
      iii. sudden unplanned outage of transmission facilities;
   b. And, that causes an unexpected change to the Responsible Entity's ACE;
   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.

B. Sudden Loss of Non-Interruptible Import:
   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the Responsible Entity's ACE.

C. Unexpected Failure of Generation to Maintain or Increase:
   a. Due to
      i. inability to start a unit the Responsible Entity planned to bring online at that time (for reasons other than lack of fuel), or
      ii. internal plant equipment problems that force the generator to be ramped down or taken offline;
   b. And that, even if not an immediate cause of an unexpected change to the Responsible Entity's ACE, will, in the Responsible Entity's judgment, leave the Responsible Entity unable to maintain its ACE following the failure unless it deploys contingency reserve.

Most Severe Single Contingency (MSSC):

The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority, to meet firm system load and non-interruptible export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event:

Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW.

Contingency Event Recovery Period:

A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period:

A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the Amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value:

The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,

or

The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

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

☐ Yes

☒ No

Comments: The *Balancing Contingency Event* definition should explicit state that generation rejection due to special protection systems (SPS) operation should not be considered as a Balancing Contingency Event since it is an anticipated and voluntary action.

Also if energy is being wheeled from BA1 to BA3 through BA2 and a contingency occurs resulting generation in BA1 being isolated from the Bulk Electric System, it is not explicit if it is the sinking Balancing Authority (BA3) or the wheeling Balancing Authority (BA2) that is experiencing the resource loss.

Finally, the *Most Single Severe Contingency* definition does not put any guidelines in how frequent it needs to be evaluated. For example, the MSSC evaluated on a complete system could be quite higher from a MSSC evaluated when transmission outages are occurring. There is a risk that a BA would not carry enough reserves to cover that contingency.

2. The proposed Purpose Statement for the draft standard is:

To ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Contingency Event.

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

☒ Yes

☐ No

Comments:

3. The BARC SDT has developed Requirement R1 to determine whether a Balancing Authority (BA) or Reserve Sharing Group (RSG) has implemented its Contingency Reserve plan and determine whether a BA or RSG met ACE recovery equal to the BA's or RSG's Most Severe Single Contingency.

R1. Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period:

- The Balancing authority or Reserve Sharing Group returned its ACE to
  - Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or
  - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.
- Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

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

☐ Yes

☒ No

Comments: When a BA experiences a Reportable Contingency Event that is larger than it's MSSC, it only needs to demonstrate that it activated reserves equal to it's MSSC. However, there is no requirement or other mechanism to validate if the MSSC was correctly evaluated at first. Based on the definitions above, the only reason why a MSSC could be greater than a Reportable Contingency Event is if non firm load or non firm exports were supported by the resource that was lost.

4. **The BARC SDT has developed a Measure for the proposed Requirement within this standard. Do you agree with the proposed Measure in this standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

5. **The BARC SDT has developed a document "BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event 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:

6. **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:

7. **Do you have any other comment on BAL-002-2, not expressed in the questions above, for the BARC SDT?**

Comments:

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Contingency Reserve for Recovery from a Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Contingency Reserve for Recovery from a Contingency Event. Comments must be submitted using 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.

Background Information:

Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of implementing a Contingency Reserve Plan.

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 five new terms to be used with this standard.**

Balancing Contingency Event:

Any single event described in subsections (A), (B), or (C) below, or any series of such otherwise single events with each separated from the next by less than one minute.

A. Sudden Loss of Generation:
   a. Due to
      i. unit tripping,
      ii. loss of generator interconnection facilities resulting in isolation of the generator from the Bulk Electric System or from the Responsible Entity's electric system, or
      iii. sudden unplanned outage of transmission facilities;
   b. And, that causes an unexpected change to the Responsible Entity's ACE;
   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.

B. Sudden Loss of Non-Interruptible Import:
   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the Responsible Entity's ACE.

C. Unexpected Failure of Generation to Maintain or Increase:
   a. Due to
      i. inability to start a unit the Responsible Entity planned to bring online at that time (for reasons other than lack of fuel), or
      ii. internal plant equipment problems that force the generator to be ramped down or taken offline;
   b. And that, even if not an immediate cause of an unexpected change to the Responsible Entity's ACE, will, in the Responsible Entity's judgment, leave the Responsible Entity unable to maintain its ACE following the failure unless it deploys contingency reserve.

Most Severe Single Contingency (MSSC):

The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority, to meet firm system load and non-interruptible export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event:

Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW.

Contingency Event Recovery Period:

A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period:

A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the Amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value:

The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,

or

The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

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

☒ Yes

☐ No

Comments:

2. The proposed Purpose Statement for the draft standard is:

To ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Contingency Event.

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

☒ Yes

☐ No

Comments:

3. **The BARC SDT has developed Requirement R1 to determine whether a Balancing Authority (BA) or Reserve Sharing Group (RSG) has implemented its Contingency Reserve plan and determine whether a BA or RSG met ACE recovery equal to the BA's or RSG's Most Severe Single Contingency.**

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     - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.
   - Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

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

☐ Yes

☒ No

Comments:

The requirement appears to be missing an element. The requirement is obligating the entity to implement its Contingency Reserve plan but there is no requirement to establish/put a plan in place.

Also, the VRF and Time Horizon are blank. Will these be filled in later?

4. The BARC SDT has developed a Measure for the proposed Requirement within this standard. Do you agree with the proposed Measure in this standard? If not, please explain in the comment area.

☒ Yes

☐ No

Comments:

The semi colon in the second line should be deleted.

5. The BARC SDT has developed a document "BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event 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:

This document restates the Requirement and only has a brief paragraph at the end describing the background and rationale. This does not provide any significant support to the Requirement.

6. 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:

7. Do you have any other comment on BAL-002-2, not expressed in the questions above, for the BARC SDT?

Comments:

Compliance, 1.2. Data Retention – the word 'previous' should be added before the words 'three calendar years'.

Compliance, 1.4. Additional Compliance Information – the third paragraph under this section seems to need more context and more detail. Perhaps add a cross reference to the definition of Reportable Contingency Event which mentions the 80% threshold.

See comments related to 5. Effective Date provided in the BAL-001 comment form.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Contingency Reserve for Recovery from a Contingency Event

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ichardson (email) or by telephone at (609) 613-1848.

Background Information:

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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 five new terms to be used with this standard.**

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   b. And, that causes an unexpected change to the Responsible Entity's ACE;
   c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.

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   a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the Responsible Entity's ACE.

C. Unexpected Failure of Generation to Maintain or Increase:
   a. Due to
      i. inability to start a unit the Responsible Entity planned to bring online at that time (for reasons other than lack of fuel), or
      ii. internal plant equipment problems that force the generator to be ramped down or taken offline;
   b. And that, even if not an immediate cause of an unexpected change to the Responsible Entity's ACE, will, in the Responsible Entity's judgment, leave the Responsible Entity unable to maintain its ACE following the failure unless it deploys contingency reserve.

Most Severe Single Contingency (MSSC):

The Balancing Contingency Event that would result in the greatest loss (measured in MW) of generation output used by the Balancing Authority, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority, to meet firm system load and non-interruptible export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink Balancing Authority).

Reportable Contingency Event:

Any Balancing Contingency Event greater than or equal to the lesser amount of 80 percent of the Balancing Authority's Most Severe Single Contingency or 500 MW.

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A period not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event.

Contingency Reserve Restoration Period:

A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, during which the Amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored.

Pre-Reportable Contingency Event ACE Value:

The value of ACE immediately prior to a Reportable Contingency Event when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,

or

The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed.

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

☐ Yes

☒ No

Comments: **We do not agree with the 500MW specification in the definition of "Reportable Contingency Event". We suggest that each Interconnection should have a unique reporting level based on frequency impact. For example, the reporting threshold could be a MW value that has an impact to frequency in that interconnection. This should result in a table with four (4) MW values, one for reporting in each Interconnection.**

We suggest changing the definition of "Reportable Contingency Event" to "Reportable Balancing Contingency Event". Will this replace the existing glossary item "Reportable Disturbance"?

We suggest that Direct Control Load Management should be taken out of the MSSC definition and rolled into the definition of Balancing Contingency Event. We are concerned that an event that is not considered as a credible event can be construed as an MSCC for an entity.
We suggest the "Contingency Reserves" definition needs to be addressed. The current NERC Glossary references BAL-002-1 for definition and this may need to be changed to BAL-012-1?

We suggest deleting Paragraph C of "Balancing Contingency Event".

We suggest the word "Reportable" be inserted before "Balancing Contingency Event" in both the Contingency Event Recovery Period and the Contingency Event Restoration Period definitions. We also suggest that "Sudden Loss" be clarified to occur within a one (1) minute time frame.

2. The proposed Purpose Statement for the draft standard is:

To ensure the Balancing Authority or Reserve Sharing Group utilizes its Contingency Reserve to balance resources and demand and return the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Contingency Event.

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

☒ Yes

☐ No

Comments:

3. The BARC SDT has developed Requirement R1 to determine whether a Balancing Authority (BA) or Reserve Sharing Group (RSG) has implemented its Contingency Reserve plan and determine whether a BA or RSG met ACE recovery equal to the BA's or RSG's Most Severe Single Contingency.

R1. Each Balancing Authority or Reserve Sharing Group experiencing a Reportable Contingency Event shall implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can demonstrate that, within the Contingency Event Recovery Period:

- The Balancing authority or Reserve Sharing Group returned its ACE to
  - Zero, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, or
  - Its Pre-Reportable Contingency Event ACE Value, less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within

the Contingency Event Recovery Period, if its ACE just prior to the Reportable Contingency Event was negative.

- Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.

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

☐ Yes

☒ No

Comments: **R1 should not require the implementation of the Contingency Reserve Plan. ACE recovery is the goal, not the implementation of the plan.**

4. **The BARC SDT has developed a Measure for the proposed Requirement within this standard. Do you agree with the proposed Measure in this standard? If not, please explain in the comment area.**

☒ Yes

☐ No

Comments:

5. **The BARC SDT has developed a document "BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event 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: **See comments in question 1.**

6. **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**

NERC

7. Do you have any other comment on BAL-002-2, not expressed in the questions above, for the BARC SDT?

Comments: **We suggest the SDT explain the absence of reporting requirements. Also explain why the data retention period was extended to 3 years from the current 1 year requirement.**

"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."

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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.
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 $_{\text{month}}$):

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

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

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 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:

$BAAL_{Low}$ 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.

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

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.

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.

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

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.

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

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

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.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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

January 2012

RELIABILITY | ACCOUNTABILITY

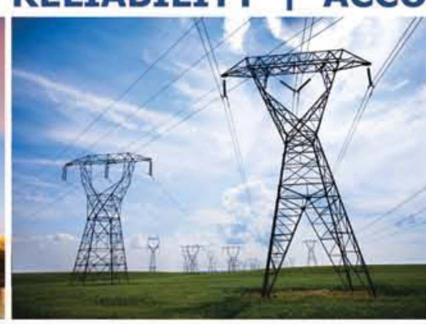

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Table of Contents

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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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}. $AVG10\text{-minute}(ACE_i) \le L_{10}$ 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.

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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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)
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Question 4 Comments (36 Responses)
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Question 5 Comments (36 Responses)
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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.
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
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:

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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:
    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.

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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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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:

Jeff Harrison	jharrison@aeci.org
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Consideration of Comments

Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-001-1

The Balancing Authority Reliability-based Controls: Reserves Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-001-1 Real Power Balancing Control Performance. These standards were posted for a 30-day public comment period from June 4, 2012 through July 3, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 38 sets of comments, including comments from approximately 136 different people from approximately 85 companies representing 9 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.

- 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.

There were a couple of minority issues that the team was unable to resolve, including the following:

- Several stakeholders felt that modifying the definition for Interconnection was outside the scope of the drafting team's SAR. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.
- Many stakeholders felt that using BAAl had caused increased inadvertent flows and transmission issues. The drafting team stated that they had not seen any issues that you are describing occur during the field trial that can 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 few stakeholders wanted to add the term "steady-state" to the purpose statement. The drafting team explained that frequency is always dynamic. The drafting team believes that adding the term steady-state would require additional clarity as to the meaning of steady-state and could create ambiguity.

- A couple of stakeholders thought that referencing an attachment in the requirement would create requirements within the attachment. The drafting team explained that the attachment was not creating any additional requirements. The attachment only provides the calculation methodology. The drafting team believes that the requirements should only state what an entity is supposed to do, not how to calculate something.
- 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 is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Project2010-14.1_Phase_1_of_Balancing_Authority_RBC.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-9723 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	Terry Bilke	ISO's Standards Review Committee		X								
2.	Group	David Dockery	Associated Electric Cooperative Inc, JRO00088	X		X		X	X				

Group 1 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM	RFC	2
2.	Steve Meyers	ERCOT	ERCOT	2
3.	Ben Li	IESO	NPCC	2
4.	Charles Yeung	SPP	SPP	2

Group 2 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative	SERC	1, 3
2.	KAMO Electric Cooperative	SERC	1, 3

NERC

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	M & A Electric Power Cooperative	SERC	1, 3										
4.	Northeast Missouri Electric Power Cooperative	SERC	1, 3										
5.	N.W. Electric Power Cooperative, Inc.	SERC	1, 3										
6.	Sho-Me Power Electric Cooperative	SERC	1, 3										
3.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Bob Solomon	Hoosier Energy	RFC	1									
2.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1									
3.	John Shaver	AEPCO	WECC	4, 5									
4.	John Shaver	SWTC	WECC	1									
4.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6									
2.	CHUCK LAWRENCE	ATC	MRO	1									
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6									
4.	JODI JENSON	WAPA	MRO	1, 2									
5.	KEN GOLDSMITH	ALTW	MRO	4									
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6									
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6									
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6									
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6									
10.	SCOTT NICKELS	RPU	MRO	4									
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3									
12.	MARIE KNOX	MISO	MRO	2									
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5									
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6									
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5									
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6									
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6									
5.	Group	Guy Zito	Northeast Power Coordinating Council										X

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Michael Lombardi	Northeast Utilities	NPCC	1
7.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
11.	Donald Weaver	New Brunswick System Operator	NPCC	2
12.	Ben Wu	Orange and Rockland Utilities	NPCC	1
13.	Robert Pellegrini	The United Illuminating Company	NPCC	1
14.	Brian Robinson	Utility Services	NPCC	8
15.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Wayne Sipperly	New York Power Authority	NPCC	5
18.	David Kiguel	Hydro One Networks Inc.	NPCC	1
19.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc,	NPCC	5
21.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
22.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
23.	Michael Jones	National Grid	NPCC	1
24.	Michael Schiavone	National Grid	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Stuart Goza	SERC OC Standards Review Group (see email list)	X		X		X				X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gerald Beckerle	Ameren	SERC	1, 3
2.	Jeff Harrison	AECI	SERC	1, 3, 5, 6
3.	Cindy Martin	Southern	SERC	1, 5
4.	Andy Burch	EEI	SERC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Larry Akens	TVA	SERC 1, 3, 5, 6										
6.	Devan Hoke	SERC	SERC 10										
7.	Wayne Van Liere	LGE-KU	SERC 3										
8.	Kelly Casteel	TVA	SERC 1, 3, 5, 6										
9.	John Jackson	LGE-KU	SERC 3										
10.	Brad Gordon	PJM	SERC 2										
11.	Randi Heise	Dominion VP	SERC 1, 3, 5, 6										
12.	Dan Roethemeyer	Dynegy	SERC 5										
13.	Jim Case	Entergy	SERC 1, 3, 6										
14.	Bill Thigpen	PowerSouth	SERC 1, 5										
15.	Jake Miller	Dynegy	SERC 5										
16.	Steve Corbin	SERC	SERC 10										
17.	Ron Carlsen	Southern	SERC 1, 3, 5										
18.	Vicky Budreau	Santee Cooper	SERC 1, 3, 5, 9										
19.	Shammara Hasty	Southern	SERC 1, 3, 5										
20.	Melinda Montgomery	Entergy	SERC 1, 3										
21.	Terry Coggins	Southern	SERC 1, 3, 5										
22.	J. T. Wood	Southern	SERC 1, 3, 5										
23.	Antonio Grayson	Southern	SERC 1, 3, 5										
24.	John Troha	SERC	SERC 10										
7.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
No additional members listed.													
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James	Murphy	WECC	1, 3, 5, 6
2.	Edison	Elizeh	WECC	1
3.	David	Kirsch	WECC	1
4.	Ayodele	Idowu	WECC	1
5.	Fran	Halpin	WECC	5
6.	Erika	Doot	WECC	3, 5, 6
7.	Meg	Albright	WECC	1

Additional Member		Additional Organization	Region	Segment Selection
8.	Pamela	Van Calcar	WECC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Guidry	Cleco Power	SPP	1, 3, 5
2.	Bryan Harper	Cleco Power	SPP	1, 3, 5
3.	Stephanie Huffman	Cleco Power	SPP	1, 3, 5
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6
7.	Fred Meyer	Empire District Electric	SPP	1
8.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
9.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
10.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
11.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 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.	Barbara Kedrowski	We-Energies	RFC	3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Individual	Brent ingebrigtson	LG&E and KU Services	X		X		X	X				
12.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
13.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
14.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
15.	Individual	Robert Blohm	Keen Resources Asia Ltd.								X		
16.	Individual	Michael Falvo	Independent Electricity System Operator		X								
17.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
18.	Individual	Daniel O'Hearn	Powerex Corp.						X				

Additional Member	Additional Organization	Region	Segment Selection
Mike Goodenough	Powerex Corp.	Seg 6	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Jeff Harrison	AECI	X		X		X	X				
21.	Individual	Greg Travis	Idaho Power Company	X		X							
22.	Individual	Michael Goggin	American Wind Energy Association								X		
23.	Individual	Thad Ness	American Electric Power	X		X		X	X				
24.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
25.	Individual	John Tolo	Tucson Electric Power	X									
26.	Individual	Kathleen Goodman	ISO New England Inc		X								
27.	Individual	Jay Campbell	NV Energy	X		X	X	X					
28.	Individual	Don Schmit	NPPD	X		X		X					
29.	Individual	Karen Webb	City of Tallahassee					X					
30.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
31.	Individual	Don Jones	Texas Reliability Entity										X
32.	Individual	Nicholas L. Hall	Constellation Energy Control and Dispatch, LLC			X							
33.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
34.	Individual	Brett Holland	KCP&L	X		X		X	X				
35.	Individual	Laura Lee	Duke Energy	X		X		X	X				
36.	Individual	Kasia Mihalchuk	Manitoba Hydro										
37.	Individual	Francis Monette	Hydro-Québec TransÉnergie										
38.	Individual	John M. Troha	SERC Reliability Corporation										

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.

Summary Consideration: Many of the commenters disagreed with the definition of Reporting Ace. The drafting team stated that they realized that this definition was more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.

Several of the commenters did not agree that there needed to be a new definition created and added to the NERC Glossary of Terms for BAAL. The drafting team agreed and removed the definition for BAAL.

A few commenters disagreed with the definition for Net Meter Error. The drafting team explained that the drafting team agrees with your comment concerning Net Metering Error (NME) and they have change the equation to use Interchange Meter Error (IME). Based on comments received from the industry the drafting team has elected to not make any modifications to how the term is defined.

A couple of commenters felt that the equation for Reporting Ace should be removed from the attachment and added to the definition. The drafting team agreed and modified the documents to reflect the suggestion.

One or two of the commenters thought that the drafting team was suggesting to remove the definition of ACE from the NERC Glossary of Terms. The drafting team explained that they were not suggesting to retire the definition for ACE. They were only trying to create a new definition for Reporting ACE.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
ISO's Standards Review Committee	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.
Response: Thank you for your comment. The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. **The drafting team agrees with your comment concerning Net Metering Error (NME) and they have change the equation to use Interchange Meter Error (IME). Based on comments received from the industry the drafting team has elected to not make any modifications to how the term is defined.**		
ACES Power Marketing Standards Collaborators	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

Organization	Yes or No	Question 1 Comment
		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.
Response: Thank you for your comment. The drafting team agrees with your comment concerning adding the term net to the definition and has added the term. The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. **The drafting team agrees with your comment concerning adding the calculation and has modified the definition.**		
MRO NSRF	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.
Response: Thank you for your comment. The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. **The drafting team agrees with your comment concerning Net Metering Error (NME) and they have change the equation to use Interchange Meter Error (IME). Based on comments received from the industry the drafting team has elected to not make any modifications to how the term is defined.**		

Organization	Yes or No	Question 1 Comment
Western Electricity Coordinating Council	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.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. **BAAL** **1 & 2 – The drafting team felt that since this term is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard.** **Reporting ACE** **1- The drafting team is not suggesting to retire the current definition of ACE. It is only recommending a new definition be added, Reporting ACE.** **2- The other standards that use the term ACE will not be modified. The term reporting ACE is presently only used in this standard. The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.** **3- Each Interconnection will need to review its standards as NERC reliability standards are modified.** **4- The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.**		
Bonneville Power Administration	No	BPA believes that the definition is subjective and only the formula should be used for the definition.
Response: Thank you for your comment. The drafting team is not sure which definition you are referencing. If it is BAAL the drafting team has removed the definition from the standard. If it is reporting ACE the drafting team believes that since ACE can vary between BAs according to control algorithms it is necessary to define reporting ACE to ensure uniformity.		
MISO Standards Collaborators	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

Organization	Yes or No	Question 1 Comment
		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.
Response: Thank you for your comment. The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. **The drafting team agrees with your comment concerning Net Metering Error (NME) and they have change the equation to use Interchange Meter Error (IME). Based on comments received from the industry the drafting team has elected to not make any modifications to how the term is defined.**		
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

Organization	Yes or No	Question 1 Comment
		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.
Response: Thank you for your comment. The drafting team felt that since the term BAAL is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard. **Each Interconnection or power pool will need to review its standards as NERC reliability standards are modified.**		
Tucson Electric Power	No	There should be an equation or formula included with the definition
Response: Thank you for your comment. The drafting team agrees and has added the equation to the definition.		
ISO New England Inc	No	Please see additional comments provided.
Response: Thank you for your comment.		
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".
Response: Thank you for your comment. The drafting team felt that since the term BAAL is only used in this standard it is not		

Organization	Yes or No	Question 1 Comment
necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard. **The drafting team realizes that this definition is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.** **The drafting team is not suggesting to retire the current definition of ACE. It is only recommending a new definition be added, Reporting ACE.**		
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)."
Response: Thank you for your comment. The drafting team felt that since the term BAAL is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard.		
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.
Response: Thank you for your comment. The variance you are describing is included in this draft of the standard. **The drafting team believes that the terms you are referencing are dealt with in reference guides either in place or under**		

Organization	Yes or No	Question 1 Comment
development and are outside the scope of this project.		
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.
Response: Thank you for your comment The drafting team felt that since the term BAAL is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard **The drafting team realizes that this definition of reporting ACE is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.**		
Manitoba Hydro	No	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.
Response: Thank you for your comment. The drafting team believes that BAL-001 speaks to the sample rate and not the accuracy of the transducers as detailed in BAL-005. However, the drafting team has removed the resolution you have		

Organization	Yes or No	Question 1 Comment
referenced from the draft standard. **The drafting team felt that since the term BAAL is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard.**		
Associated Electric Cooperative Inc, JRO00088	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.
Response: Thank you for your comment. The drafting believes that since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. The drafting team has added the calculation to the definition.		
LG&E and KU Services	Yes	LG&E and KU Services suggest removing “reliability risk” from the end of the first sentence in the BAAL definition
Response: Thank you for your comment. The drafting team felt that since the term BAAL is only used in this standard it is not necessary for it to be included in the NERC Glossary of Terms and has removed it from the standard.		
Idaho Power Company	Yes	Although WECC is pursuing a Regional Variation to include the WECC ATEC term into the reporting ACE which is needed.
Response: Thank you for your comment. The variance you are describing is included in this draft of the standard.		
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

Organization	Yes or No	Question 1 Comment
		appear to match the calculation in Attachment 1.
Response: Thank you for your comment. The drafting team believes that the current definition for Control Performance Standard is still acceptable and no modification is necessary. **The drafting team has removed the reference to the standard from the definition and added the calculation.**		
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	
Progress Energy	Yes	
Arizona Public Service Company	Yes	
Hydro-Québec TransÉnergie	Yes	
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
Powerex Corp.	Yes	
SERC Reliability Corporation	Yes	
AECI	Yes	

Organization	Yes or No	Question 1 Comment
American Wind Energy Association	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	

2. The SDT has modified the definition for the term Interconnection. Please view the new definition shown in redline on the Unofficial Word version posted on the project page which shows the changes proposed. http://www.nerc.com/filez/standards/Project2010-14.1_Phase_1_of_Balancing_Authority_RBC.html

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

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

Summary Consideration: Several of the commenters felt that modifying the definition for Interconnection was outside the scope of the drafting team's SAR. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.

Many of the commenters wanted the term "Texas" changed to "ERCOT". The drafting team agreed and made the necessary modifications to the definition.

Organization	Yes or No	Question 2 Comment
ISO's Standards Review Committee	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.
Response: Thank you for your comment. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.		
Western Electricity Coordinating Council	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.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The drafting team agrees and has made the necessary modification.		
Bonneville Power Administration	No	BPA understands that this is an update to the existing definition, but it is not a definition. This is simply identifying the interconnections.
Response: Thank you for your comment.		
MISO Standards Collaborators	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.
Response: Thank you for your comment. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.		
Texas Reliability Entity	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.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modification.		
Xcel Energy	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.
Response Thank you for your comment. The drafting team agrees and has made the necessary modification.		
MRO NSRF	Yes	While the NSRF agrees with these four entities comprise the four major

Organization	Yes or No	Question 2 Comment
		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.
Response: Thank you for your comment. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.		
Independent Electricity System Operator	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.
Response: Thank you for your comment. The drafting team disagrees with you regarding the SAR. The SAR states that the drafting team is to address the directives from FERC Order 693. One of these directives was to establish a continent wide contingency reserve policy. Since Quebec is part of the continent therefore the term Interconnection should be corrected.		
Tucson Electric Power	Yes	Somewhat vague definition. It's more identifying the interconnections.
Response: Thank you for your comment.		
Duke Energy	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.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modification.		
Manitoba Hydro	Yes	
Hydro-Québec TransÉnergie	Yes	
Associated Electric Cooperative Inc, JRO00088	Yes	

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	
Progress Energy	Yes	
SERC Reliability Corporation	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
Sacramento Municipal Utility District	Yes	
Powerex Corp.	Yes	
AECI	Yes	
Idaho Power Company	Yes	
American Wind Energy Association	Yes	

Organization	Yes or No	Question 2 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
ISO New England Inc	Yes	
NV Energy	Yes	
City of Tallahassee	Yes	
South Carolina Electric and Gas	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	

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.

Summary Consideration: Several of the commenter disagreed with the use of the term "in support of interconnection frequency" in the purpose statement. The drafting team stated that they agreed with their comment. This further explained that this was an error in the comment report.

A few of the commenters wanted to add the term "steady-state" to the purpose statement. The drafting team explained that frequency is always dynamic. The drafting team believes that adding the term steady-state would require additional clarity as to the meaning of steady-state and could create ambiguity.

A couple of commenters wanted to add the phrase "by balancing real power supply and demand in real-time" to the purpose statement. The drafting team stated that they agreed that controlling interconnection frequency is accomplished by balancing power supply and demand. However, the drafting team believes that adding the additional words does not provide any additional clarity.

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative Inc, JRO00088	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.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
ACES Power Marketing Standards Collaborators	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.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The drafting team believes that frequency is always dynamic. The drafting team believes that adding the term steady-state would require additional clarity as to the meaning of steady-state and could crate ambiguity.		
SERC Reliability Corporation; SERC OC Standards Review Group	No	Delete “in support of interconnection frequency”.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
Bonneville Power Administration	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.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
MISO Standards Collaborators	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.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
LG&E and KU Services	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.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
Progress Energy	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

Organization	Yes or No	Question 3 Comment
		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.
Response: Thank you for your comment. The drafting team believes that transient frequency deviations to avoid UFLS are addressed in the proposed BAL-003-1 standard. **The drafting team conducts a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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 Corp.	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.
Response: Thank you for your comment. The drafting team understands your concern. However, the drafting team does not know of any analysis that has been done that directly ties the use of BAAL with the problems that you have identified. **BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but**		

Organization	Yes or No	Question 3 Comment
restrict those that do have a detrimental effect on reliability.		
AECI	No	Delete "in support of interconnection frequency".
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
Tucson Electric Power	No	This purpose statement does not match the purpose statement in the proposed Standard.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
NV Energy	No	My suggestion: "To control Interconnection frequency within defined limits."
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
City of Tallahassee	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.
Response: Thank you for your comment. The drafting team disagrees with your suggestion. The drafting team believes that this standard should address Interconnection frequency which is achieved by individual BA control performance.		
South Carolina Electric and Gas	No	South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Response: Thank you for your comment. The drafting team believes that frequency is always dynamic. The drafting team believes that adding the term steady-state would require additional clarity as to the meaning of steady-state and could crate ambiguity.		
Texas Reliability Entity	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."

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The drafting team agrees that controlling interconnection frequency is accomplished by balancing power supply and demand. However, the drafting team believes that adding the additional words does not provide any additional clarity.		
Xcel Energy	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”.
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
Duke Energy	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.
Response: Thank you for your comment. This was an error in the comment report. However, based on comments received from the industry the drafting team has decided to not make the modification you suggest.		
Keen Resources Asia Ltd.	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!
Response: Thank you for your comment. The drafting team agrees with your comment. This was an error in the comment report.		
Constellation Energy Control and Dispatch, LLC	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,

Organization	Yes or No	Question 3 Comment
		its intent is clearly not the simple support or control of frequency.
Response: Thank you for your comment.		
ISO's Standards Review Committee	Yes	
Manitoba Hydro	Yes	
MRO NSRF	Yes	
Hydro-Québec TransÉnergie	Yes	
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
Idaho Power Company	Yes	
American Wind Energy Association	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
ISO New England Inc	Yes	

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.

Summary Consideration: many of the commenters thought that the present wording of Requirement R1 was sufficient and should not be changed. The drafting team stated that they had only made minor modifications to the proposed requirement from the present requirement. The wording for Requirement R1 is virtually the same as it is today. The drafting team does not know of any issues that have arisen with the present wording.

A few of the commenters disagreed with the phrase "to support Interconnection Frequency". The drafting team agreed with the commenter and removed the language from the requirement.

One commenter expressed concern with the use of Reporting ACE and that some of the equations were still using ACE. The drafting team explained that the equations had been changed to use Reporting ACE. The drafting team further stated that since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.

One commenter questioned whether an attachment was considered part of a standard and therefore enforceable. They also were unsure of how modifications to an attachment would be handled. The drafting team stated that the attachment was part of the standard and is therefore enforceable. To make any modifications to an attachment you must go through the same process (the Standard development Process) as if you were changing a requirement.

Another commenter thought that referencing an attachment in the requirement would create requirements within the attachment. The drafting team explained that the attachment was not creating any additional requirements. The attachment only provides the calculation methodology. The drafting team believes that the requirements should only state what an entity is supposed to do, not how to calculate something.

Organization	Yes or No	Question 4 Comment
Western Electricity Coordinating Council	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?

Response: Thank you for your comment.

1) The drafting team agrees and has removed the language.

Organization	Yes or No	Question 4 Comment
2) The drafting team is not attempting to modify the existing definitions. The terms have been changed in the attachment. **3) The drafting team agrees and has made the modification to now use IME.** **4) The equations have been changed to use Reporting ACE. The drafting team realizes that this definition of reporting ACE is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.** **5) The attachment is part of the standard and is therefore enforceable. To make any modifications to an attachment you must go through the same process (the Standard development Process) as if you were changing a requirement.**		
Bonneville Power Administration	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.
Response: Thank you for your comment. The drafting team disagrees with your comment. The attachment does not create any additional requirements. The attachment only provides the calculation methodology. The drafting team believes that the requirements should only state what an entity is supposed to do, not how to calculate something.		
MISO Standards Collaborators	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

Organization	Yes or No	Question 4 Comment
		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.
Response: Thank you for your comment. The drafting team has only made minor modifications to the proposed requirement from the present requirement. The wording for Requirement R1 is virtually the same as it is today. The drafting team does not know of any issues that have arisen with the present wording. The present requirement does not state a rolling 12-months. The drafting team has modified the attachment to use the same language throughout.		
Tucson Electric Power	No	There appears to be no change in CPS1 calculations or requirements so the current BAL-001-0.1a is preferred.
Response: Thank you for your comment. The drafting team has only made minor modifications to the proposed requirement from the present requirement. The wording for Requirement R1 is virtually the same as it is today.		
ISO New England Inc	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.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The drafting team assumes you are commenting on 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 **The drafting team has not seen any issues concerning the "time of day short term frequency excursions" during the field trial.** **The drafting team has not seen any issues that you are describing occur during the field trial that can be directly attributable to the use of BAAL.**		
Xcel Energy	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.
Response: Thank you for your comment. The drafting team agrees and has removed the language.		
ISO's Standards Review Committee	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.
Response: Thank you for your comment. The drafting team has only made minor modifications to the proposed requirement from the present requirement. The wording for Requirement R1 is virtually the same as it is today. The drafting team does not know of any issues that have arisen with the present wording. The present requirement does not state a rolling 12-months. The drafting		

Organization	Yes or No	Question 4 Comment
team has modified the attachment to use the same language throughout.		
Manitoba Hydro	Yes	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.
Response: Thank you for your comment. The drafting team agrees and has modified the requirement accordingly.		
Associated Electric Cooperative Inc, JRO00088	Yes	AECI agrees with this existing and unmodified requirement.
Response: Thank you for your comment.		
ACES Power Marketing Standards Collaborators	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.
Response: Thank you for your comment.		
MRO NSRF	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.
Response: Thank you for your comment. The drafting team has only made minor modifications to the proposed requirement from the present requirement. The wording for Requirement R1 is virtually the same as it is today. The drafting team does not know of any issues that have arisen with the present wording. The present requirement does not state a rolling 12-months. The drafting team has modified the attachment to use the same language throughout.		
SERC OC Standards Review Group	Yes	This is an existing requirement and was not modified by the standard drafting team.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment.		
South Carolina Electric and Gas	Yes	South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Response: Thank you for your comment.		
SPP Standards Review Group	Yes	
Hydro-Québec TransÉnergie	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
pwx	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
Powerex Corp.	Yes	
AECI	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 4 Comment
American Wind Energy Association	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
NV Energy	Yes	
City of Tallahassee	Yes	
Texas Reliability Entity	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	
Duke Energy	Yes	

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.

Summary Consideration: Several commenters felt that using BAAl has caused increased inadvertent flows and transmission issues. The drafting team stated that they had not seen any issues that you are describing occur during the field trial that can 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 few of the commenters wanted to change the equations for BAAL from using 60 Hz to use Scheduled Frequency. The drafting team agreed and made the necessary modifications.

A couple of the commenters disagreed with the phrase "to support Interconnection Frequency". The drafting team agreed with the commenter and removed the language from the requirement.

A few of the commenters felt that BAs would operate in a manner that would allow them to be non-compliant for a large part of the 30-minute window used by BAAL and that they had seen this operation used by BAs in the west. The drafting team explained that to operate in the manner they had described would be a very high risk method of operation. The drafting team believes that the performance of the BAs would not become worse but would in fact be better if there if this standard was enforceable and there were compliance penalties involved.

A couple of other commenters 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 is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.

One commenter felt that the elimination of CPS2 could have a detrimental impact on reliability when frequency is in the opposite direction. The drafting team stated that neither BAAL nor CPS2 guarantees that a BA whose generation is in a direction

that supports interconnection frequency will not result in transmission issues. BAs with large ACE during periods when transmission issues are present should be addressed by the RC.

Organization	Yes or No	Question 5 Comment
Associated Electric Cooperative Inc, JRO00088	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.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modifications.		
Hydro-Québec TransÉnergie	No	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.
Response: Thank you for your comment. The drafting team acknowledges that your field trial is conducted using different limits. 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.		
Northeast Power Coordinating Council	No	As with BAL-013-1, should "clock-minutes" be replaced with "minutes"?

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The drafting team believes that "clock-minutes" is a more descriptive term.		
Western Electricity Coordinating Council	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?
Response: Thank you for your comment. **1) The drafting team agrees and has removed the language.** **2) The attachment is part of the standard and is therefore enforceable. To make any modifications to an attachment you must go through the same process (the Standard development Process) as if you were changing a requirement.**		
Bonneville Power Administration	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.
Response: Thank you for your comment. The drafting team understands your disagreement with the question but cannot provide a response without further information. **The drafting team disagrees with your comment. The attachment does not create any additional requirements. The attachment only provides the calculation methodology. The drafting team believes that the requirements should only state what an entity is supposed to do, not how to calculate something.**		

Organization	Yes or No	Question 5 Comment
SPP Standards Review Group	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.
Response: Thank you for your comment. The drafting team believes that this standard is dealing with regulating reserves and not deployment of contingency reserves. The drafting team has not seen the issue that you are describing occur during the field trial that can 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.		
MISO Standards Collaborators	No	The proposed changes in BAL-003 with regard to variable bias (no floor on variable bias) open the opportunity for gaming R2.
Response: Thank you for your comment. The drafting team disagrees with your comment. The latest developments in BAL-003 provide minimum values for Frequency Bias settings when variable bias is used in multi-BA interconnections.		
Arizona Public Service Company	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

Organization	Yes or No	Question 5 Comment
		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.
Response: Thank you for your comment. 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 **The drafting team will continue to evaluate results from the field trial until this standard has become effective.** **To operate in the manner you have described would be a very high risk method of operation. The drafting team believes that the performance of the BAs would not become worse but would in fact be better if there if this standard was enforceable and there were compliance penalties involved.**		
Powerex Corp.	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.

Organization	Yes or No	Question 5 Comment
		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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>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.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. To operate in the manner you have described would be a very high risk method of operation. The drafting team believes that the performance of the BAs would not become worse but would in fact be better if there if this standard was enforceable and there were compliance penalties involved.

The drafting team chose 30 minutes to be consistent with other NERC standards.

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.

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. 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.

The drafting team acknowledges that the frequency band has increased but it is still within the FTL that has been selected for the Interconnection. In addition, the drafting team has not seen any analysis done that would provide information pointing to the use of BAAL and the violations you are describing.</td></tr>
<tr><td>AECI</td><td>No</td><td>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</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		BAAL calculation will adjust for time error correct.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modifications.		
Tucson Electric Power	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.
Response: Thank you for your comment. The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.		
ISO New England Inc	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.
Response: Thank you for your comment. The drafting team has considered other alternative approaches and has selected the 3 epsilon model as the best and fairest model for the requirement.		

Organization	Yes or No	Question 5 Comment
The drafting team has not seen any issues concerning the "time of day short term frequency excursions" during the field trial. The drafting team has not seen any issues that you are describing occur during the field trial that can 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.		
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.
Response: Thank you for your comment. The drafting team believes that neither BAAL nor CPS2 guarantees that a BA whose generation is in a direction that supports interconnection frequency will not result in transmission issues. BAs with large ACE during periods when transmission issues are present should be addressed by the RC.		
City of Tallahassee	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.
Response: Thank you for your comment. The drafting team understands that the 30 minute time frame may require more unit response but the drafting team believes that the 30 min requirement is appropriate. 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.		
Texas Reliability Entity	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?

Organization	Yes or No	Question 5 Comment
		How will this requirement be evaluated if there is a generation loss event greater than the MSSC?
Response: Thank you for your comment. The drafting team understands your concern about the waiver. However, the drafting team believes that this is an issue that should be addressed by the applicable entity. **The drafting team believes that EEA's presently do not provide for exclusion from other standards that are in effect.** **The requirement would be evaluated in the same manner that it is evaluated when there is no generation loss. The drafting team has not seen any issues that you are describing occur during the field trial that can be directly attributable to the use of BAAL.**		
Constellation Energy Control and Dispatch, LLC	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

Organization	Yes or No	Question 5 Comment
		actual intent of R2, as well as that of R1.
Response: Thank you for your comment. The drafting team believes that there appears to be a misunderstanding of how BAAL is calculated. BAAL calculations use actual frequency, actual ACE and does provide a mechanism to support system frequency as you suggest.		
Xcel Energy	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.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modifications. **There is language in the attachment to provide for instances when measuring equipment are inoperable.**		
ACES Power Marketing Standards Collaborators	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?

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. There is language in the attachment to provide for instances when measuring equipment are inoperable.		
Manitoba Hydro	Yes	The reference to 'it' should specify the Balancing Authority for clarity.
Response: Thank you for your comment. The drafting team agrees and has made the necessary modifications.		
MRO NSRF	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.
Response: Thank you for your comment. The latest developments in BAL-003 provide minimum values for Frequency Bias settings when variable bias is used in multi-BA interconnections.		
SERC OC Standards Review Group	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.
Response: Thank you for your comment. The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.		
LG&E and KU Services	Yes	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 comment.		
NV Energy	Yes	While I generatlly agree with the intent or R2, it's too wordy. I suggest "Each

Organization	Yes or No	Question 5 Comment
		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."
Response: The drafting team thanks you for your comment but the drafting team has elected to not use your suggested wording based on the comments received from the industry.		
South Carolina Electric and Gas	Yes	South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group.
Response: Thank you for your comment. Please refer to our response to the comments submitted by the SERC OC Standards Review Group.		
Duke Energy	Yes	See comment to question 1 on the use of Reporting ACE.
Response: Thank you for your comment. Please refer to our response to the comments submitted for Question 1.		
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
Idaho Power Company	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 5 Comment
Association		
American Electric Power	Yes	
Tacoma Power	Yes	
ISO's Standards Review Committee	Yes	

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.

Summary Consideration: The majority of the commenters agreed that the VRFs were appropriate for the requirements.

One commenter suggested that the VRF be based on the impact that the BA has on the interconnection. The drafting team stated that they were 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. The drafting team used the current VRF Development Guideline.

Another commenter thought the "medium" VRF was excessive and quoted the first sentence of the VRF guideline. The drafting team explained that they had only provided the first sentence of the VRF Guideline for a medium VRF. The second sentence reads "…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." This is the sentence that the drafting team makes this a medium VRF. In addition, the current approved VRF for this requirement in BAL-001-0.1a is also a medium VRF.

Organization	Yes or No	Question 6 Comment
Associated Electric Cooperative Inc, JRO00088	No	AECI concurs with the concerns expressed by SERC on behalf of smaller BAs.
Response: Thank you for your comment. Please refer to our response to the comments submitted by SERC.		
SERC OC Standards Review Group	No	See comments to No. 5 above.
Response: Thank you for your comment. Please refer to our response to Question 5.		

Organization	Yes or No	Question 6 Comment
Powerex Corp.	No	No comment at this time.
AECI	No	VRFs should be adjusted based upon the balancing authorities impact upon the interconnection.
Response: Thank you for your comment. The drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs. The drafting team used the current VRF Development Guideline.		
NV Energy	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".
Response: The drafting team thanks you for your comment but the drafting team disagrees. You have only provided the first sentence of the VRF Guideline for a medium VRF. The second sentence reads "…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." This is the sentence that the drafting team makes this a medium VRF. In addition, the current approved VRF for this requirement in BAL-001-0.1a is also a medium VRF.		
South Carolina Electric and Gas	No	
Texas Reliability Entity	Yes	There is a reference to BAL-003-1 that appears misplaced in the VRF/VSL justification document (please verify).
Response: Thank you for your comment. This has been corrected.		
ISO's Standards Review Committee	Yes	

Organization	Yes or No	Question 6 Comment
ACES Power Marketing Standards Collaborators	Yes	
MRO NSRF	Yes	
Western Electricity Coordinating Council	Yes	
Manitoba Hydro	Yes	
Hydro-Québec TransÉnergie	Yes	
Bonneville Power Administration	Yes	
SPP Standards Review Group	Yes	
MISO Standards Collaborators	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	

Organization	Yes or No	Question 6 Comment
Idaho Power Company	Yes	
American Wind Energy Association	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Tucson Electric Power	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	
Duke Energy	Yes	

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.**

Summary Consideration: The majority the majority of the commenters agreed that the measures were appropriate for the requirements.

One commenter disagreed with the measure since they disagreed with the requirement. Their concern was with the treatment of small BAs. The drafting team stated that they were aware of the concern identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.

Another commenter disagreed with the measures because they felt that the Data Retention section appeared to exclude the use of hard copy for data retention. The drafting team explained that the measures do not reference the data input. They only reference the method for proving compliance. The data retention references the data used for the calculation that needs to be retained.

One commenter felt it was unclear if the data required must be EMS quality of if the data could be from another source. The drafting team stated that data retention referenced "scan rate" data. As long as an entity can provide "scan rate" data it should not matter where it comes from. This is the same that is presently in effect with standard BAL-001-0.1a.

Organization	Yes or No	Question 7 Comment
Bonneville Power Administration	No	BPA does not agree with the requirements in general, and cannot support the measures.
Response: Thank you for your comment. Please refer to our response to your comments concerning the requirements.		
Powerex Corp.	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

Organization	Yes or No	Question 7 Comment
		any penalty or sanction.
Response: Thank you for your comment. Please refer to our response to Question 5.		
Tucson Electric Power	No	Need to address the BAAL calculation for small BAs
Response: Thank you for your comment. The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.		
City of Tallahassee	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.
Response: Thank you for your comment. The measures do not reference the data input. They only reference the method for proving compliance. The data retention references the data used for the calculation that needs to be retained.		
Xcel Energy	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.
Response: Thank you for your comment. The data retention references "scan rate" data. As long as an entity can provide "scan rate" data it should not matter where it comes from. This is the same that is presently in effect with standard BAL-001-0.1a.		
ISO's Standards Review Committee	Yes	
Associated Electric Cooperative Inc, JRO00088	Yes	
ACES Power Marketing	Yes	

Organization	Yes or No	Question 7 Comment
Standards Collaborators		
MRO NSRF	Yes	
SERC OC Standards Review Group	Yes	
Manitoba Hydro	Yes	
SPP Standards Review Group	Yes	
MISO Standards Collaborators	Yes	
Hydro-Québec TransÉnergie	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
AECI	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 7 Comment
American Wind Energy Association	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
NV Energy	Yes	
South Carolina Electric and Gas	Yes	
Texas Reliability Entity	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	
Duke Energy	Yes	

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.**

Summary Consideration: The majority the majority of the commenters agreed that the VSLs were appropriate for the requirements.

A couple of commenters disagreed with the VSLs based on the objection to Requirement R2 and the treatment of small BAs. The drafting team stated that they were aware of the concern identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.

One commenter disagreed with the VSLs and felt that they should be graded by the size of entity in lieu of having multiple VRFs. The drafting team explained that under the present guidelines a standard must have a VRF and VSL. The VRFs account for the impact the requirement could have on the BES while the VSL accounts for the severity of the violation of the requirement. The drafting team does not know of any way to differentiate the VSL based on the size of an entity. The drafting team believes to differentiate based on the size would add a large degree of subjectivity based on the thresholds used.

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	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.
Response: Thank you for your comment.		
Powerex Corp.	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.
Response: Please refer to our response to Question 5.		

Organization	Yes or No	Question 8 Comment
ISO's Standards Review Committee	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.
Response: Thank you for your comment. The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.		
MRO NSRF	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.
Response: Thank you for your comment. The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.		
SERC OC Standards Review Group	Yes	Perhaps VSLs could be graded by the size of the entity in lieu of having multiple VRFs.
Response: Thank you for your comment. Under the present guidelines a standard must have a VRF and VSL. The VRFs account for the impact the requirement could have on the BES while the VSL accounts for the severity of the violation of the requirement. The drafting team does not know of any way to differentiate the VSL based on the size of an entity. The drafting team believes to differentiate based on the size would add a large degree of subjectivity based on the thresholds used.		
Western Electricity Coordinating Council	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.
Response: Thank you for your comment. The drafting team will ensure that any modifications to the requirements will be reflected in the VSLs.		

Organization	Yes or No	Question 8 Comment
South Carolina Electric and Gas	Yes	South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group
Response: Please refer to our response to comments submitted by the SERC OC Standards Review Group.		
Associated Electric Cooperative Inc, JRO00088	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Bonneville Power Administration	Yes	
SPP Standards Review Group	Yes	
MISO Standards Collaborators	Yes	
Southern Company	Yes	
Manitoba Hydro	Yes	
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
AECI	Yes	

Organization	Yes or No	Question 8 Comment
Idaho Power Company	Yes	
American Wind Energy Association	Yes	
Hydro-Québec TransÉnergie	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
Texas Reliability Entity	Yes	
Constellation Energy Control and Dispatch, LLC	Yes	
Duke Energy	Yes	

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.

Summary Consideration: Several commenters wanted the field trial data included in the Background Document. The drafting team stated that they conduct a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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.

Some commenters disagreed with the statement made by the drafting team that there has not been any reliability issues occur during the field trial. The drafting team explained that there have not been any reliability issues raised by any RC during the monthly 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.

A few commenters mentioned that there was an error in the description of A1 criteria located in the Background Document. The drafting team agreed with the commenter and modified the document to reflect the correct language.

A couple of commenters felt that the Background Document provided valuable material and that it should be retained. The drafting team agreed and stated that they would recommend that NERC keep the document on their website.

Organization	Yes or No	Question 9 Comment
ISO's Standards Review Committee	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.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **1) The drafting team does not intend for this document to replace anything. The document was only intended to provide insight into the drafting teams thought process during the development of this standard.** **2) Thank you and this will be corrected.**		
MRO NSRF	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.
Response: Thank you for your comment. This will be corrected.		
Western Electricity Coordinating Council	No	The background document should include the Field Trial results from all Interconnections.
Response: Thank you for your comment. The drafting team conducts a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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.		
Bonneville Power Administration	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.
Response: Thank you for your comment. 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		

Organization	Yes or No	Question 9 Comment
share any specific occurrences that they feel have reliability impacts as a result of operating under BAAL. **The Background Document does not address the relative reliability of CPS2 versus BAAL. The 72 hours that a BA could be outside the CPS2 and be fully compliant was an observation and not an implication of reliability. The drafting team believes that operating to the limits of any measure is an extremely high risk operation.**		
MISO Standards Collaborators	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.
Response: Thank you for your comment. This will be corrected.		
Progress Energy	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.
Response: Thank you for your comment. The drafting team conducts a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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.		
Keen Resources Asia Ltd.	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

Organization	Yes or No	Question 9 Comment
		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.
Response: Thank you for your comment. The drafting team has considered other alternative approaches and has selected the 3 epsilon model as the best and fairest model for the requirement. **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.**		
Independent Electricity System Operator	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.
Response: Thank you for your comment. This will be corrected.		

Organization	Yes or No	Question 9 Comment
Powerex Corp.	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.
Response: Thank you for your comment. The drafting team conducts a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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. **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.**		
Tucson Electric Power	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.
Response: Thank you for your comment. The drafting team understands that there has been some transmission flow issues reported that are presently being investigated by the WECC Performance Working Group. However, 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.		
ISO New England Inc	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.
Response: Thank you for your comment. The drafting team believes that this is a NERC Standards Process issue and is therefore outside the scope of this project. However, the draft standards are evaluated by individuals trained to perform quality reviews. The drafting team believes that if this standard was not able to stand on its own, it would be identified during the quality review		

Organization	Yes or No	Question 9 Comment
process.		
City of Tallahassee	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.
Response: Thank you for your comment. The drafting team is unsure of the type of additional information you are seeking. We encourage you to contact those participating in the field trial to seek their feedback on any operational issues encountered during the field trial. **The drafting team conducts a monthly call to discuss the prior month operation using BAAL. These monthly results are posted on the NERC website. The BAAL field trial will continue in effect until the date that a new standard goes into effect. 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.**		
Xcel Energy	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.
Response: Thank you for your comment. The drafting team does not agree that a link is needed for the Background Document. However, the drafting team is providing a link to the documents below. **http://www.nerc.com/filez/standards/Reliability_Based_Control_FieldTrial_Tools_2007-18-RF.html**		
SPP Standards Review Group	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.
Response: Thank you for your comment. The drafting team will recommend that this document be archived in an appropriate place for future reference.		

Organization	Yes or No	Question 9 Comment
Arizona Public Service Company	Yes	Yes, provides clarity but there remains disagreement with the rationale.
Response: Thank you for your comment.		
Constellation Energy Control and Dispatch, LLC	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.
Response: Thank you for your comment. Please refer to our response for Question 5.		
Duke Energy	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."
Response: Thank you for your comment. The drafting team agrees and has made the necessary modifications.		
Associated Electric Cooperative Inc, JRO00088	Yes	

Organization	Yes or No	Question 9 Comment
ACES Power Marketing Standards Collaborators	Yes	
Hydro-Québec TransÉnergie	Yes	
Manitoba Hydro	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
Sacramento Municipal Utility District	Yes	
AECI	Yes	
Idaho Power Company	Yes	
American Wind Energy Association	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
NV Energy	Yes	
South Carolina Electric and Gas	Yes	

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.

Summary Consideration: A few commenters felt that the current version of the standard could provide an entity the opportunity to crate large inadvertent flows by operating under BAAL. The drafting team stated that they had not seen any issues that they were describing occur during the field trial that can 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.

One commenter disagreed with using the term Reporting ACE and that this could cause problems with other standards. The drafting team explained that they believed that defining a new term "reporting ACE" would allow consistent evaluation of individual BAs performance to CPS1 and BAAL. The drafting team realizes that this definition of reporting ACE is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. The drafting team further explained that they did not believe that the proposed standard would create any problems with other standards. Standards are written to be stand-alone. For this fact alone, there should not be any negative impacts. The drafting team has evaluated several other standards and has not found any instances of ambiguity being created.

Another commenter wanted to combine BAL-001 and BAL-002. The drafting team stated that they had discussed combining the standards into one but chose to keep them separate. The drafting team believes that combining the two standards could create additional confusion. In addition, the drafting team believes that it would be difficult to get industry agreement.

Organization	Yes or No	Question 10 Comment
NV Energy		I am not aware of conflicts.
Response: Thank you for your comment.		
Powerex Corp.		In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for unscheduled energy flows between

Organization	Yes or No	Question 10 Comment
		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.

Response: Thank you for your comment. The drafting team has not seen any issues that you are describing occur during the field trial that can be directly attributable to the use of BAAL. BAAL was designed to provide for better control by allowing power flows

Organization	Yes or No	Question 10 Comment
that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability. **The drafting team believes that BAAL is not intended to solve all issues. The standards (BAL) taken together and interacting together solve issues.**		
Duke Energy		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”?
Response: Thank you for your comment. The drafting team believes that EOP issues are beyond the scope of this drafting team. However, the drafting team will pass you concern on the appropriate individuals at NERC for future consideration.		

Organization	Yes or No	Question 10 Comment
An entity must maintain compliance with all standards that are applicable. The standards are not intended to tell an entity how it should maintain compliance.		
MISO Standards Collaborators		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.
Response: Thank you for your comment. The drafting team believes that defining a new term "reporting ACE" will allow consistent evaluation of individual bas performance to CPS1 and BAAL. The drafting team realizes that this definition of reporting ACE is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity. **The drafting team does not believe that the proposed standard will create any problems with other standards. Standards are written to be stand-alone. For this fact alone, there should not be any negative impacts. The drafting team has evaluated several other standards and has not found any instances of ambiguity being created.**		

Organization	Yes or No	Question 10 Comment
Keen Resources Asia Ltd.		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!

Response: Thank you for your comment. The drafting team has considered other alternative approaches and has selected the 3 epsilon model as the best and fairest model for the requirement.

The drafting team conducts a monthly call to review the results from the BAAL field trial. There have not been any reliability

Organization	Yes or No	Question 10 Comment
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.		
Manitoba Hydro		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.
Response: Thank you for your comment. The drafting team has removed the resolution from the draft standard.		
Xcel Energy		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.
Response: Thank you for your comment. The drafting team would need further clarification to be able to respond to your comment concerning a conflict. The drafting team does not see anything that would appear to be conflicting. **The drafting team has discussed combining the standards into one but chose to keep them separate. The drafting team believes that combining the two standards could create additional confusion. In addition, the drafting team believes that it would be difficult to get industry agreement.**		
Associated Electric Cooperative Inc, JRO00088		No

Organization	Yes or No	Question 10 Comment
Tucson Electric Power		no
South Carolina Electric and Gas		No
SERC OC Standards Review Group		No.
Arizona Public Service Company		None noted
Idaho Power Company		None.
SPP Standards Review Group		Not aware of any conflicts.

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

Summary Consideration: Some commenters felt that six months was not enough time in implement BAAL. The drafting team stated that they had seen BAs make modification to their EMS for the field trial within 3 months and therefore believes that the six month window is appropriate.

A couple of commenters felt that using BAAL created transmission issues. The drafting team explained that they conduct 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. 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 few commenters felt that the applicability section contained "requirements". The drafting team stated that they had modified the applicability section to provide additional clarity.

A couple of commenters disagreed with modifying the term "Interconnection". The drafting team explained that they modified the definition to add clarity with regards to the proper names of the Interconnections. The drafting team asked the question if the industry agreed with this modification. Only 6 entities disagreed. The drafting team agrees with the fact that this term is used in many standards but does not believe that the modification will have any significant impact.

A few commenters questioned the fact that the standard did not contain any reporting requirement. The drafting team explained that they had not included any reporting requirements because they believed that this was a function that should be handled by the RC and/or ERO.

One or two commenters felt that using BAAL would significantly restrict smaller BAs. The drafting team stated that they were aware of the concern identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs.

One commenter disagreed with the language in the Compliance Enforcement Authority. The drafting team explained that they had modified the language to use standard NERC approved language.

Organization	Yes or No	Question 11 Comment
ISO's Standards Review Committee		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

Response: Thank you for your comment.

1) The drafting team is only correcting the definition for Interconnection. The drafting team believes that since there are four Interconnections on the North American Continent then the definitions should be corrected.

2) The drafting team agrees and has removed it from the standard.

3) Based on comments received the drafting team believes that the definition for reporting ACE is correct as modified in the draft

Organization	Yes or No	Question 11 Comment
standard. **4) & 5) The drafting team thanks you for your suggestion and has modified the applicability section to provide clarity.** **6) The drafting team agrees and has made the necessary modifications.**		
Texas Reliability Entity		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...).
Response: Thank you for your comment. **1) The drafting team has modified the applicability section to provide additional clarity. The drafting team believes that ERCOT is described in section 4.1.** **2) The drafting team has modified the calculation and NME is now IME. In addition, everything within the calculation is done in MWs.** **3) The "excluded values" calculation has not changed from what is being done today. The calculation will be done in the same manner as it always has been calculated.**		
City of Tallahassee		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

Organization	Yes or No	Question 11 Comment
		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?
Response: Thank you for your comment. **1) The drafting team has seen BAs make modification to their EMS for the field trial within 3 months and therefore believes that the six month window is appropriate.** **2) The drafting team is using standard language for the data retention.** **3) The drafting team does not have any knowledge of any changes, but changes are made by the NERC RS and approved by the NERC OC.**		
Western Electricity Coordinating Council		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

Organization	Yes or No	Question 11 Comment
		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.

Response: Thank you for your comment.

1) The drafting team is aware of the concern you have identified. However, the drafting team is attempting to develop a standard that would be applicable to the entire continent and does not know of any method to distinguish between larger and smaller BAs. In addition, the drafting team has modified the equation to now use Scheduled Frequency.

2 a & b) 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

Organization	Yes or No	Question 11 Comment
that they feel have reliability impacts as a result of operating under 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.		
Progress Energy		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
Response: Thank you for your comment. The field trial experience in the East does not demonstrate the behavior you are describing. In addition, RCs have not reported any issues related to excessive ace during the monthly calls. **The drafting team has removed the resolution you have referenced.**		
Associated Electric Cooperative Inc, JRO00088		AECI agrees with SERC comment that Attachment 1 Interconnection names should agree with those in the draft Interconnection definition.
Response: Thank you for your comment. The drafting team has modified the documents so that they are consistent in the use of Interconnection names.		
Manitoba Hydro		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.

Organization	Yes or No	Question 11 Comment
		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.
Response: Thank you for your comment. The drafting team has corrected the error you have described. **The drafting team is using standard NERC approved language for the effective dates.**		
American Wind Energy Association		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.
Response: Thank you for your comment.		
Northeast Power Coordinating Council		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.

Organization	Yes or No	Question 11 Comment
		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?
Response: Thank you for your comment. The drafting team has explored the alternative model that is described and has chosen to go with the 3 Epsilon model. **The drafting team has not seen any issues that during the field trial that can 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.** **CPS1 data submission requirements have been expanded to provide the number of valid samples in each month.** **The attachment states that if the one minute sample is bad then it is excluded from the calculation.**		
Duke Energy		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

Organization	Yes or No	Question 11 Comment
		specified in the Background Information for Quality Reviews dated February 2012.
Response: Thank you for your comment. The drafting team has modified the applicability section to provide additional clarity. **Thank you for catching this error. The drafting team has corrected the reference.** **The drafting team has modified the Compliance Enforcement Authority to use standard NERC approved language.**		
MRO NSRF		General Comments and Observations o The drafting team changed the NERC definition of Interconnections. This term is used in many standards and may have impact on them. o 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.
Response: Thank you for your comment. The drafting team modified the definition to add clarity with regards to the proper names of the Interconnections. The drafting team asked the question if the industry agreed with this modification. Only 6 entities disagreed. The drafting team agrees with the fact that this term is used in many standards but does not believe that the modification will have any significant impact. **The drafting team realizes that this definition of reporting ACE is more prescriptive. Since ACE can vary between BAs according to control algorithms the drafting team felt it was necessary to define reporting ACE to ensure uniformity.** **The drafting team has removed the resolution from the attachment.** **The Net Metering Error (NME) has changed to Interchange Meter error (IME). Based on industry comments received, the drafting team has elected to not make any modifications to the term.**		
LG&E and KU Services		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

Organization	Yes or No	Question 11 Comment
		continuously.
Response: Thank you for your comment. The drafting team has not included any reporting activity within the standard. The drafting team believes that reporting will be determined by the RC and ERO.		
MISO Standards Collaborators		MISO supports this standard generally and, in particular, the concept and use of BAAL in lieu of CPS2.
Response: Thank you for your comment.		
Tucson Electric Power		Please note and read the WECC PWG report on RBC. Thanks to the drafting team for their efforts.
Response: Thank you for your comment. The drafting team plans on reading the report once it is published.		
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.
Response: Thank you for your comment. All BAs are subject to this standard with the exception of those BAs receiving Overlap Regulation Service. **The drafting team has modified the applicability to provide additional clarity.**		
Independent Electricity System Operator		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

Organization	Yes or No	Question 11 Comment
		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.
Response: The drafting team thanks you for your comment and has modified the applicability section to provide clarity.		
SERC OC Standards Review Group		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.
Response: Thank you for your comment. The drafting team has not included any reporting activity within the standard. The drafting team believes that reporting will be determined by the RC and ERO. **The drafting team thanks you for catching this error and they have made the necessary modifications.**		
South Carolina Electric and Gas		South Carolina Electric and Gas supports the comments submitted by the SERC OC Standards Review Group.
Response: Thank you for your comment. Please refer to our response to the comments submitted by the SERC OC Standards Review Group.		
Constellation Energy Control and Dispatch, LLC		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.
Response: Thank you for your comment. The drafting team has modified the applicability to no longer reference BAs providing		

Organization	Yes or No	Question 11 Comment
Overlap Regulation Service.		
SPP Standards Review Group		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?
Response: Thank you for your comment. The drafting team has seen BAs make modification to their EMS for the field trial within 3 months and therefore believes that the six month window is appropriate. **The exemption would stay in effect until the new standard goes into effect.** **A variance can be requested by anyone at anytime.**		
ACES Power Marketing Standards Collaborators		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

Organization	Yes or No	Question 11 Comment
		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.

Response: Thank you for your comment. The drafting team has seen BAs make modification to their EMS for the field trial within 3 months and therefore believes that the six month window is appropriate

Organization	Yes or No	Question 11 Comment
The drafting team thanks you for finding this error. The drafting team has made the necessary modifications to correct this oversight. The Net Metering Error (NME) has changed to Interchange Meter error (IME). Based on industry comments received, the drafting team has elected to not make any modifications to the term. The drafting team thanks you for finding this error. The drafting team has made the necessary modifications to correct this oversight. The drafting team believes that data should be retained as defined in the current standard. This is the same as required by many other standards in effect. A quick search of the Rules of Procedure (ROP) did not find anything that would imply that this recommended data retention period is conflicting with the ROP. The drafting team has removed the resolution from the attachment.		
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.
Response: Thank you for your comment. The drafting team agrees that CPS2 is an independent measure of a BAs performance. It is		

Organization	Yes or No	Question 11 Comment
not a function on Interconnection Frequency and can result in individual BA control that does not support interconnection frequency. 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.		
Powerex Corp.		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

Organization	Yes or No	Question 11 Comment
		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

Organization	Yes or No	Question 11 Comment
		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.

Response: Thank you for your comment.

1) The drafting team believes that this is outside the scope of the industry approved SAR and that transmission priority is a NAESB concern. The drafting team recommends that you submit a SAR if you feel that this should be pursued further.

2) The drafting team believes that your reference to a minimum regulating reserve requirement from FERC Order 693 is contained in Phase 2 of Project 2010-14.

3 & 4) 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. 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

Organization	Yes or No	Question 11 Comment
have a detrimental effect on reliability.		
Bonneville Power Administration		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 BAsIn 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.
Response: Thank you for your comment. The drafting team has modified the applicability section to address your comment and other comments from the industry. **The drafting team plans to review the paper you referenced once the document has been published.**		
American Electric Power		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

Organization	Yes or No	Question 11 Comment
		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.
Response: Thank you for your comment. FERC has stated that it is the ultimate responsibility of the BA to ensure balance of load and generation in a reliable manner.		
Arizona Public Service Company		No comments
NV Energy		No.
Idaho Power Company		None

END OF REPORT

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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 45-day formal comment period beginning on March 12, 2013 through April 25, 2013.

Future Development Plan:

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.

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

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 - $3\varepsilon1_I$ Hz)

$\boldsymbol{FTL_{High}}$ is the High Frequency Trigger Limit (calculated as F_S + $3\varepsilon1_I$ Hz)

Where $\varepsilon1_I$ is the constant derived from a targeted frequency bound for each Interconnection as follows:

- Eastern Interconnection $\varepsilon1_I$ = 0.018 Hz
- Western Interconnection $\varepsilon1_I$ = 0.0228 Hz
- ERCOT Interconnection $\varepsilon1_I$ = 0.030 Hz
- Quebec Interconnection $\varepsilon1_I$ = 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.

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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 45-day formal comment period beginning on March 12, 2013 through April 25, 2013.

Future Development Plan:

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~~$_{\text{High}}$~~) and a low limit (BAAL~~$_{\text{Low}}$~~).~~

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.

$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$ 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:

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

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
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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
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0.1a	October 29, 2008	Board approved errata changes; updated version number to “0.1a”	Errata

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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:~~

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

~~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.~~

~~**I_{ME} (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.

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

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

~~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:

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

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

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

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

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

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.~~

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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.~~ 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.

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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

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 45-day formal comment period beginning on March 12, 2013 through April 25, 2013.

Future Development Plan:

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.

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
    a. Due to
        i. Unit tripping,
        ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
        iii. Sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected change to the responsible entity's ACE.
C. Sudden loss of a known load used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency or 500 MW and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reportable Contingency Event ACE Value: The average value of ACE in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual event basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

4.1. Balancing Authority

4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.2. 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. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero):
  - o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and
  - o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their

Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

Or,

- Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative),
    - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and
    - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.

R2. Except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert Level 2 or 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, including additional documentation on any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with the amounts identified in Requirement R2 except within the first 105 minutes following an event requiring the activation of Contingency Reserve.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered from a Reportable	The Responsible Entity recovered from a Reportable	The Responsible Entity recovered from a Reportable	The Responsible Entity recovered from a Reportable

	Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	Balancing Contingency Event during the Contingency Event Recovery Period but recovered 70% or less of required recovery.
R2	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 5 hours but less than or equal to 15 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 15 hours but less than or equal to 25 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 25 hours but less than or equal to 35 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 35 hours.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth	Errata

		bullet.	
2		NERC BOT Adoption	Complete revision

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 45-day formal comment period beginning on March 21, 2013 through April 25, 2013.

Future Development Plan:

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.

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of g~~G~~eneration:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility~~ies~~ resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility~~ies~~;
   b. And, that causes an unexpected change to the responsible entity's ACE;
   ~~c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.~~

~~B.~~ Sudden l~~L~~oss of an~~Non-Interruptible~~ i~~I~~mport~~:~~, due to forced outage of transmission equipment that causes an unexpected change to the responsible entity's ACE.

~~a.~~B. ~~A sudden loss of a non-interruptible import, due to forced outage of transmission equipment that causes an unexpected change to the responsible entity's ACE.~~

~~C.~~ Sudden loss of a known load used as a resource that causes an unexpected change to the responsible entity's ACE.~~Unexpected Failure of Generation to Maintain or Increase:~~

~~a. Due to~~
~~i. Inability to start a unit the responsible entity planned to bring online at that time (for reasons other than lack of fuel), or~~
~~ii. Internal plant equipment problems that force the generator to be ramped down or taken offline;~~

~~b.~~C. ~~And that, even if not an immediate cause of an unexpected change to the responsible entity's ACE, will, in the responsible entity's judgment, leave the responsible entity unable to maintain its ACE following the failure, unless it deploys Contingency Reserve.~~

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource~~generation~~ output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event~~, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority,~~ to meet firm system load and ~~non-interruptible~~ export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the ~~Balancing Authority's~~ Most Severe Single Contingency or 500 MW and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter~~not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event~~.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period~~, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored~~.

Pre-Reportable Contingency Event ACE Value: The average value of ACE in the 16 second interval immediately prior to the start of the~~a Reportable~~ Contingency Event Recovery Period based on EMS scan rate data~~when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,~~

~~or~~

~~The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed~~.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event~~meet the Disturbance Control Standard (DCS)~~ and other ~~NERC and Regional Reliability Organization~~ contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group ~~utilizes its Contingency Reserve to~~ balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual event basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

4.1. Balancing Authority

4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.2. 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. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the Responsible Entity~~Each Balancing Authority or Reserve Sharing Group~~ experiencing a Reportable Balancing Contingency Event shall ~~implement its Contingency Reserve plan so that the Balancing Authority or Reserve Sharing Group can~~ demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to~~, within the Contingency Event Recovery Period~~: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero)~~The Balancing Authority or Reserve Sharing Group returned its ACE to~~:
  - ~~Zero,~~ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~if its ACE just prior to the Reportable Contingency Event was positive or equal to zero, Or~~

- o Further reduced by the ~~Its Pre-Reportable Contingency Event ACE Value, less the sum of the~~ magnitude~~s~~ of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable~~all subsequent~~ Balancing Contingency Event~~s~~ and all previous Balancing Contingency Events that have not completed their~~that occur within the~~ Contingency Event Restoration~~Recovery~~ Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~, if its ACE just prior to the Reportable Contingency Event was negative.~~

Or,

- Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative),
  - o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and
  - o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~Provided, however, that in either of the foregoing cases, if the Reportable Contingency Event (individually or when combined with any previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods) exceeded the Balancing Authority's or Reserve Sharing Group's Most Severe Single Contingency (MSSC), then the Balancing Authority or Reserve Sharing Group need only demonstrate ACE recovery of at least equal to its MSSC, less the sum of the magnitudes of all Previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Periods.~~

R2. Except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert Level 2 or 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, including additional documentation on any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.~~Each Balancing Authority or Reserve Sharing Group shall have, and provide upon request, evidence; such as computer~~

~~logs or operator logs, with date and time of occurrence to show compliance with Requirement R1.~~

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with the amounts identified in Requirement R2 except within the first 105 minutes following an event requiring the activation of Contingency Reserve.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~The~~ 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.~~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 or Reserve Sharing Group~~ 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.

If a Responsible Entity~~Balancing Authority or Reserve Sharing Group~~ 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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

~~A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group.~~

The Responsible Entity~~A Balancing Authority or Reserve Sharing Group~~ may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

~~A Balancing Authority or Reserve Sharing Group may optionally reduce the 80 percent threshold, upon written notification to the Regional Entity.~~A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 70% or less of required recovery.
R2	In each calendar quarter, the Responsible Entity had Contingency Reserves but its	In each calendar quarter, the Responsible Entity had Contingency Reserves but its	In each calendar quarter, the Responsible Entity had Contingency Reserves but its	In each calendar quarter, the Responsible Entity had Contingency Reserves but its

	Contingency Reserve was deficient for more than 5 hours but less than or equal to 15 hours.	Contingency Reserve was deficient for more than 15 hours but less than or equal to 25 hours.	Contingency Reserve was deficient for more than 25 hours but less than or equal to 35 hours.	Contingency Reserve was deficient for more than 35 hours.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

Implementation Plan

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

Implementation Plan for BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facilities;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import due to forced outage of transmission equipment that causes an unexpected change to the responsible entity's ACE.
C. Sudden loss of a known load used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency, or 500 MW and occurring within a rolling one-minute interval based on EMS scan rate data.

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reportable Contingency Event ACE Value: The average value of ACE in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other NERC contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation..

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 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 pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan

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

Implementation Plan for BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of g~~G~~eneration:
   a. Due to
      i. U~~u~~nit tripping,
      ii. L~~l~~oss of generator Interconnection Facility~~ies~~ resulting in isolation of the generator from the Bulk Electric System or from the responsible entity’s electric system, or
      iii. S~~s~~udden unplanned outage of transmission Facilities;
   b. And, that causes an unexpected change to the responsible entity’s ACE;
   ~~c. Provided, however, that normal, recurring operating characteristics of a unit do not constitute sudden or unanticipated losses and may not be subject to this definition.~~
B. Sudden l~~L~~oss of an~~Non-Interruptible~~ Import due to forced outage of transmission equipment that causes an unexpected change to the responsible entity’s ACE.~~:~~
   ~~a. A sudden loss of a non-interruptible import, due to forced outage of transmission equipment, that causes an unexpected change to the responsible entity’s ACE.~~

~~C.~~ Sudden loss of a known load used as a resource that causes an unexpected change to the responsible entity's ACE.~~Unexpected Failure of Generation to Maintain or Increase:~~

~~a. Due to~~

~~i. Inability to start a unit the responsible entity planned to bring online at that time (for reasons other than lack of fuel), or~~

~~ii. Internal plant equipment problems that force the generator to be ramped down or taken offline;~~

~~b.~~C. ~~And that, even if not an immediate cause of an unexpected change to the responsible entity's ACE, will, in the responsible entity's judgment, leave the responsible entity unable to maintain its ACE following the failure unless it deploys Contingency Reserve.~~

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource~~generation~~ output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event~~, or the greatest loss of activated Direct Control Load Management used by the Balancing Authority~~ to meet firm s~~S~~ystem l~~L~~oad and ~~non-interruptible~~ export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the ~~Balancing Authority's~~ Most Severe Single Contingency, or 500 MW and occurring within a rolling one-minute interval based on EMS scan rate data.

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter~~not exceeding 15 minutes following the start of the Balancing Contingency Event. The start of the Balancing Contingency Event is the point in time where the first change in MW is observed due to the event~~.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period~~, during which the amount of Contingency Reserve deployed to recover from a Balancing Contingency Event is to be restored~~.

Pre-Reportable Contingency Event ACE Value: The average value of ACE in the 16 second interval immediately prior to the start of the ~~a Reportable~~ Contingency Event Recovery Period based on EMS scan rate data~~when there are no previous Reportable Contingency Events for which the Contingency Event Recovery Period is not yet completed,~~

~~or~~

~~The value of ACE that the Balancing Authority or Reserve Sharing Group must attain to fully meet its ACE recovery requirement with respect to the immediately previous Reportable Contingency Event for which the Contingency Event Recovery Period is not yet completed~~.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event~~meet the Disturbance Control Standard (DCS)~~ and other NERC ~~and Regional Reliability Organization~~ contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation..

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 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 pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

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:

Unofficial Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event

Please **do not** use this form to submit comments on the proposed revisions to BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event. 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:
Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

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 modified the definition for Balancing Contingency Event based on comments received from the industry. Do you agree that the modifications provide addition clarity? If not, please explain in the comment area below.**

   ☐ Yes
   ☐ No

   Comments:

2. **The BARC SDT has modified the current definition for Contingency Reserve. Do you agree that the modified definition provides for greater clarity? If not, please explain in the comment area below.**

☐ Yes

☐ No

Comments:

3. **The BARC SDT has created a definition for Reserve Sharing Group Reporting ACE. Do you agree with this definition? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

4. **The BARC SDT has added language to the proposed requirements in the standard and to the definition for Contingency Reserve to resolve any conflicts between this standard and the EOP standards. Do you agree that this modification was necessary and that any possible issues are now resolved? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

5. **The BARC SDT has developed Requirement R2 which requires entities to have Contingency Reserve at least equal to its MSSC. This requirement was added to address, in conjunction with Requirement R1, the FERC Directive for a continent wide Contingency Reserve policy. Do you agree that this addresses the FERC Directive? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

6. **The BARC SDT has assigned both Requirement R1 and Requirement R2 a "medium" VRF. Do you agree with the proposed VRF? If not, please explain in the comment area below.**

   ☐ Yes

   ☐ No

   Comments:

7. **The BARC SDT has assigned both Requirement R1 and Requirement R2 a Time Horizon of "Real-time Operations". Do you agree with the Time Horizon the SDT has chosen? If not, please explain in the comment area below.**

☐ Yes

☐ No

Comments:

8. **The BARC SDT has developed VSLs for Requirement R1 and Requirement R2. Do you agree with the VSLs in this standard? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

9. **The BARC SDT has made significant modifications to the Background Document based on industry comments received. Do you agree that these modifications provide additional clarity as to the development of this standard? If not, please explain in the comment area.**

   ☐ Yes

   ☐ No

   Comments:

10. **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 the issue.**

    Comments:

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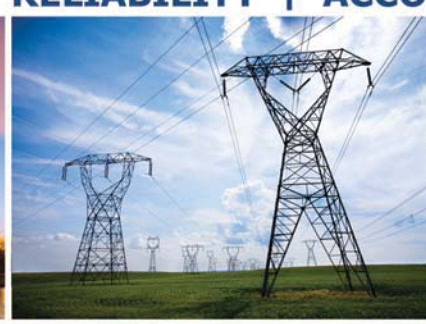


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Table of Contents

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:
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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 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.

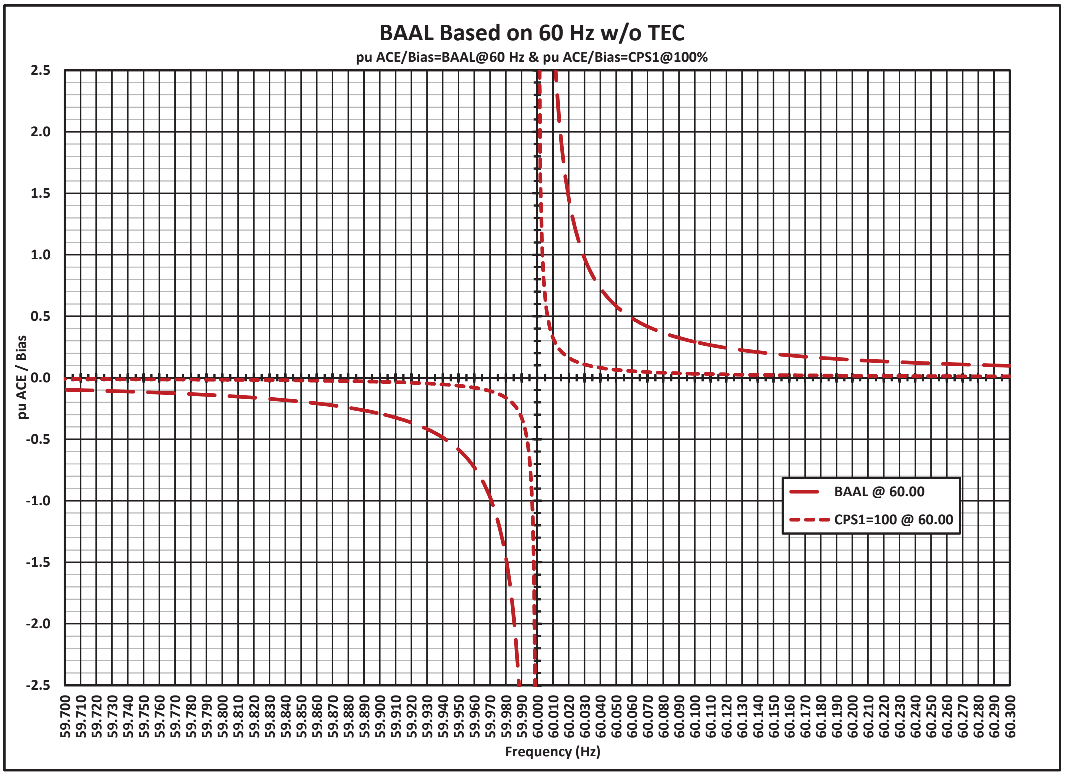

Figure 2. BAAL Based on 60 Hz w/o TEC

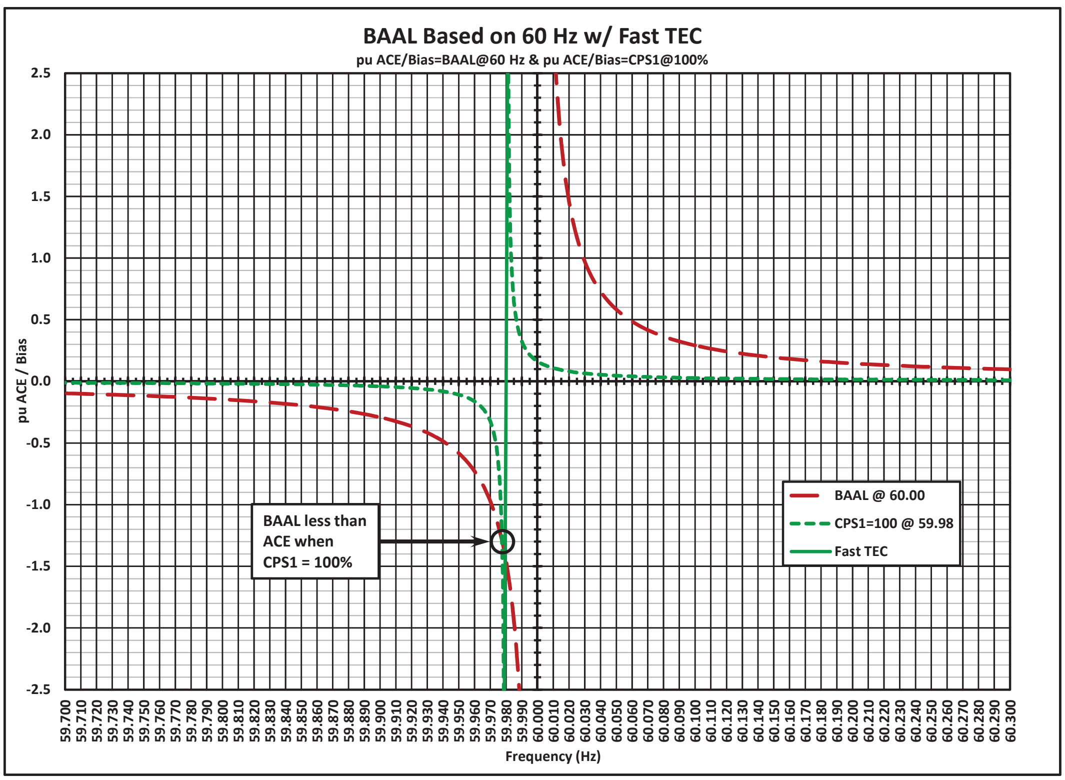

Figure 1. BAAL Based on 60 Hz w/ Fast TEC

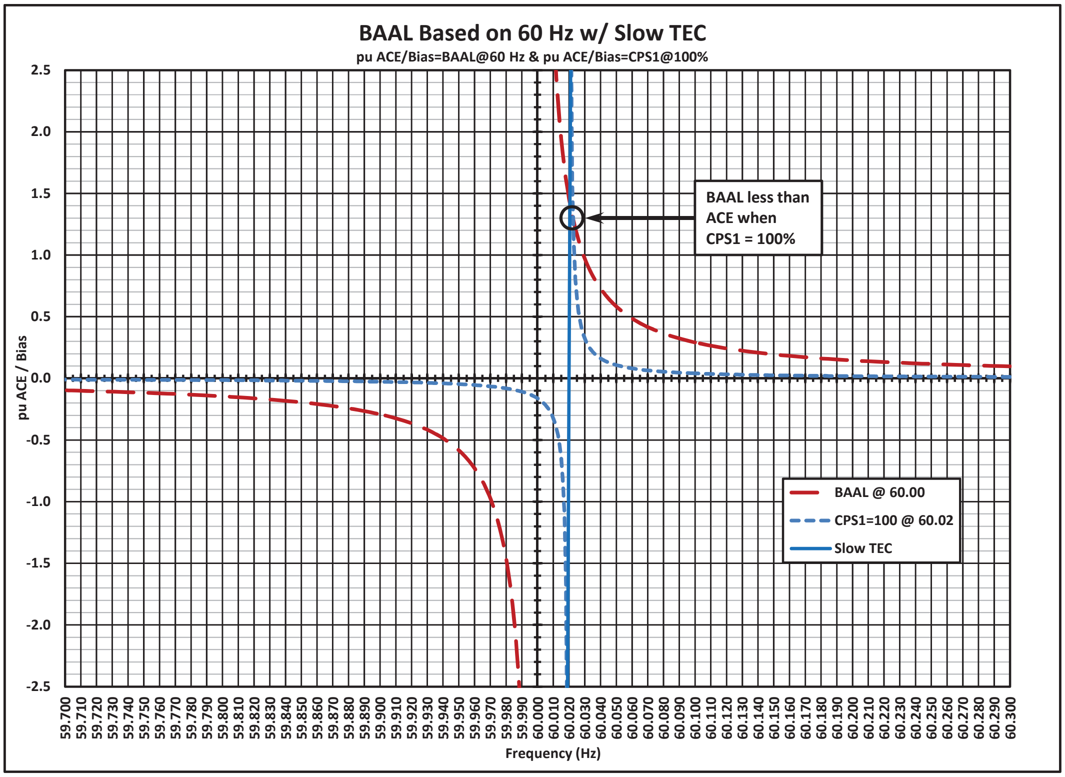

Figure 4. BAAL Based on 60 Hz w/ Slow TEC

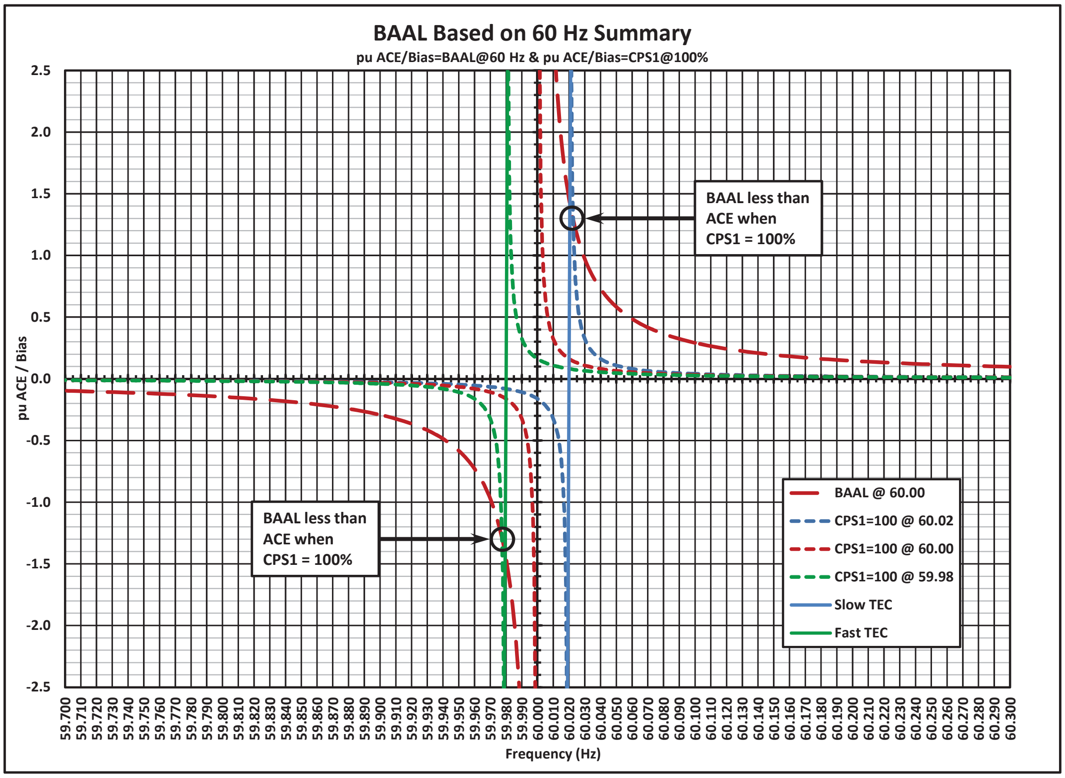

Figure 3. BAAL Based on 60 Hz Summary

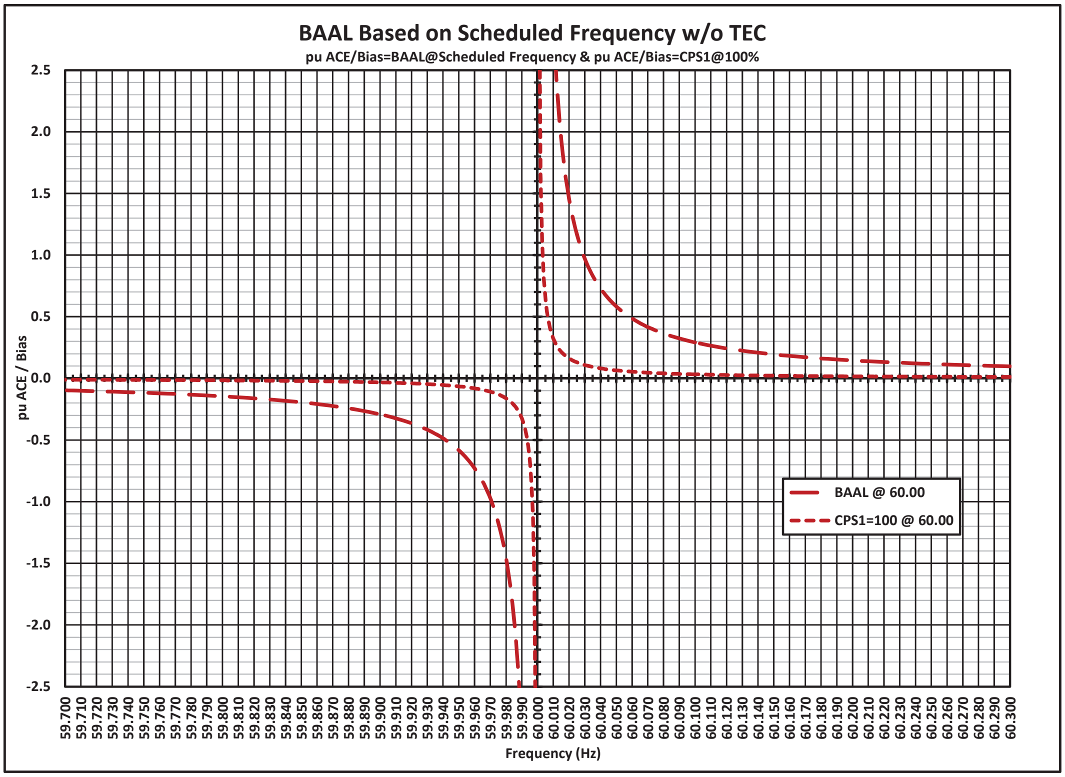

Figure 6. BAAL Based on Scheduled Frequency w/o TEC

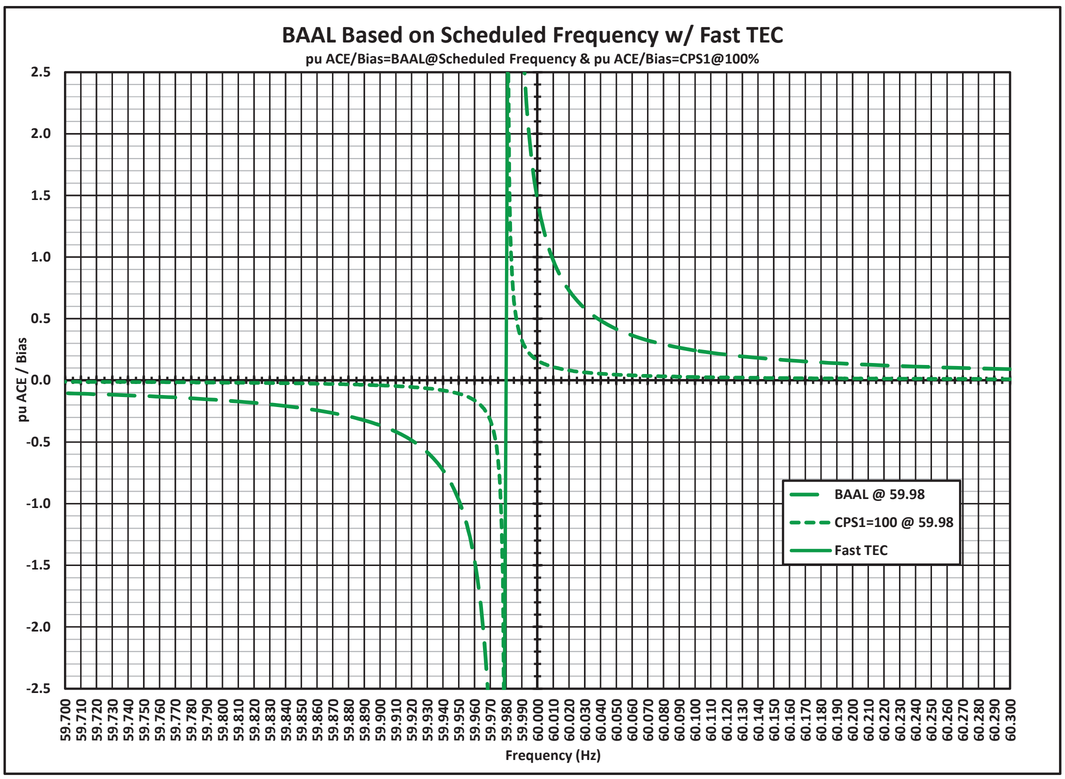

Figure 5. BAAL Based o Scheduled Frequency w/ Fast TEC

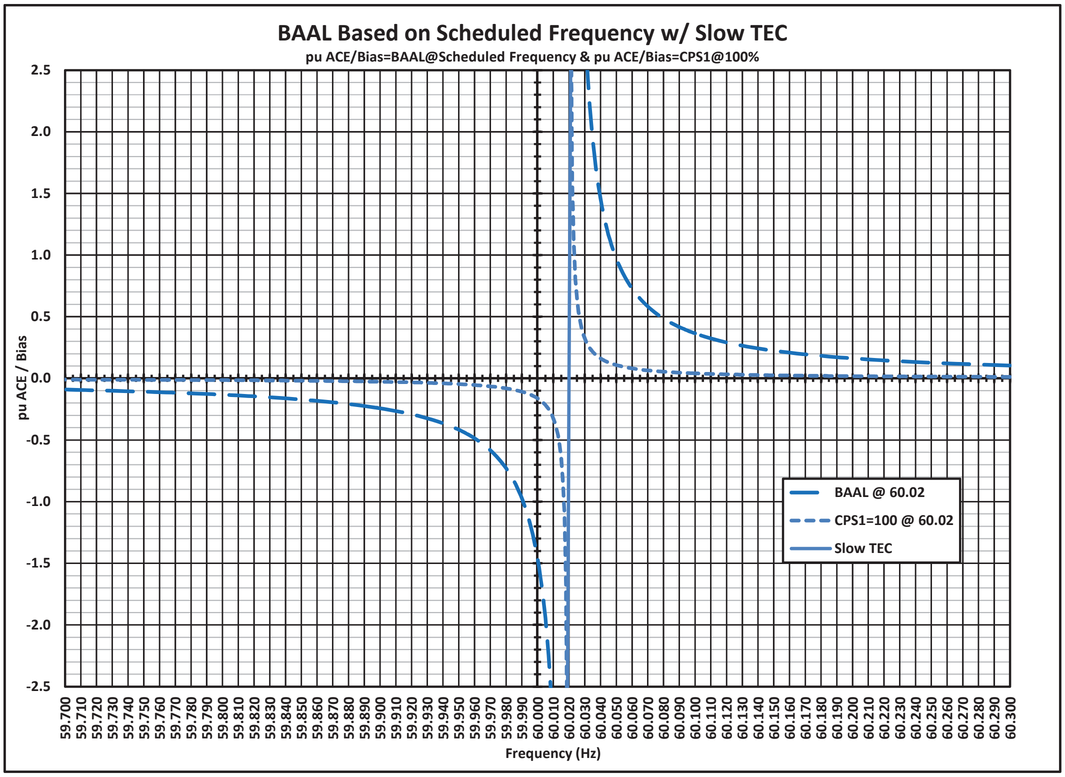

Figure 7. BAAL Based on Scheduled Frequency w/ Slow TEC

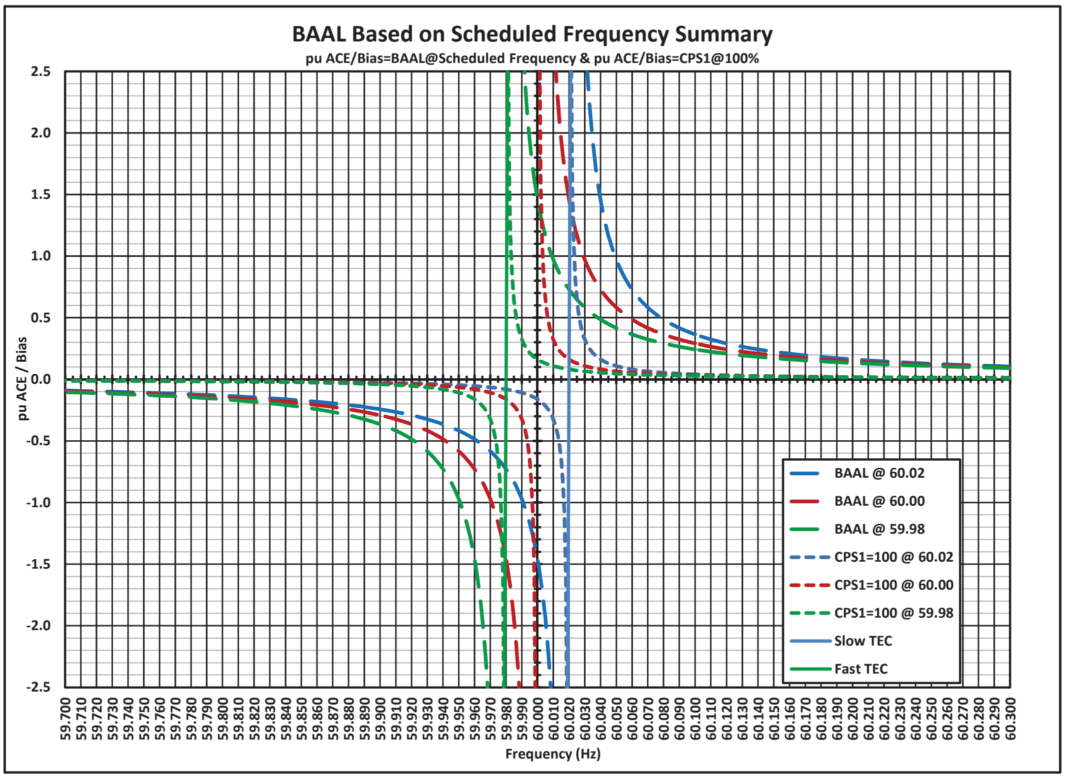

Figure 8. BAAL Based on Scheduled Frequency Summary

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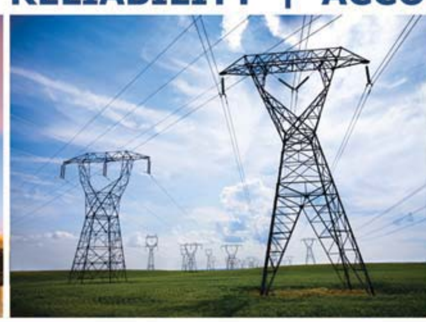


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The proposed BAL-001-~~1~~ 2 retains CPS1, but proposes a new measure BAAL to replace CPS2. Currently CPS2:

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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.

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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.

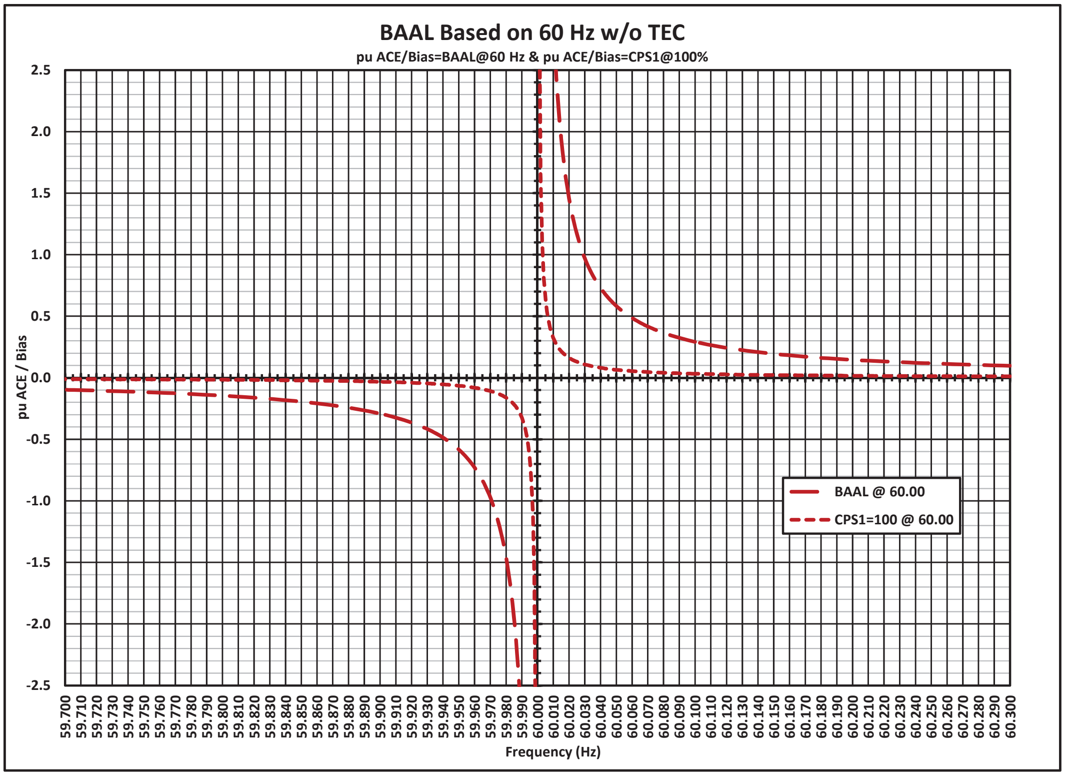

Figure 2. BAAL Based on 60 Hz w/o TEC

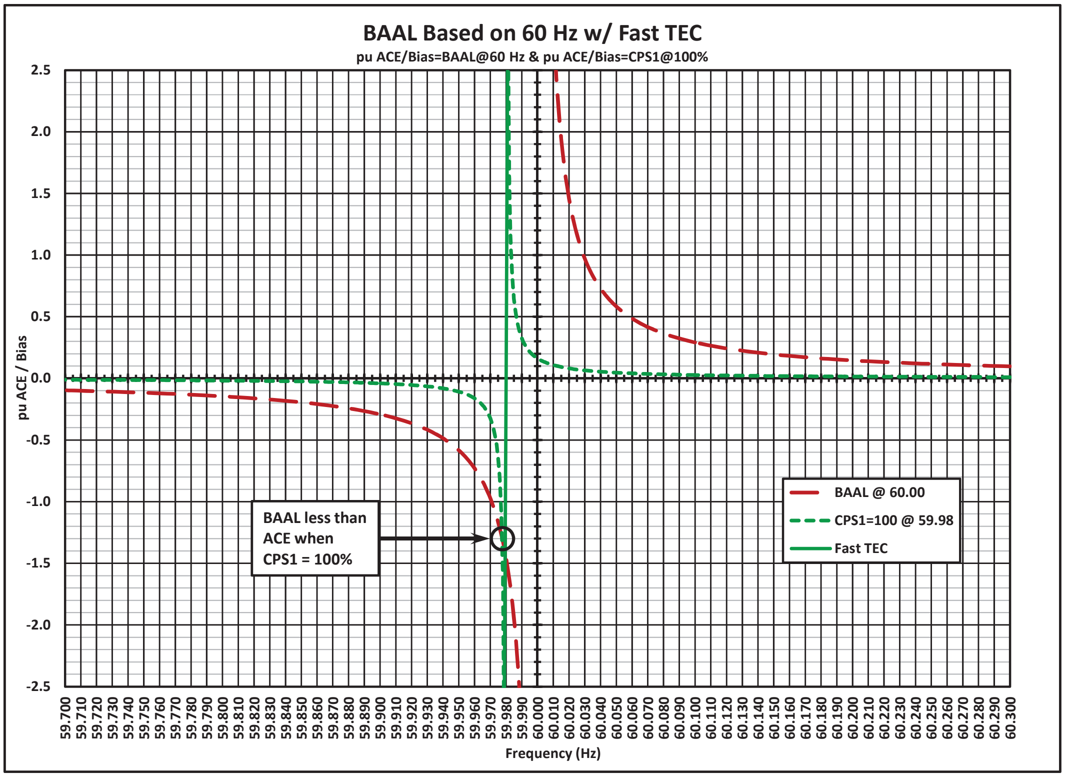

Figure 1. BAAL Based on 60 Hz w/ Fast TEC

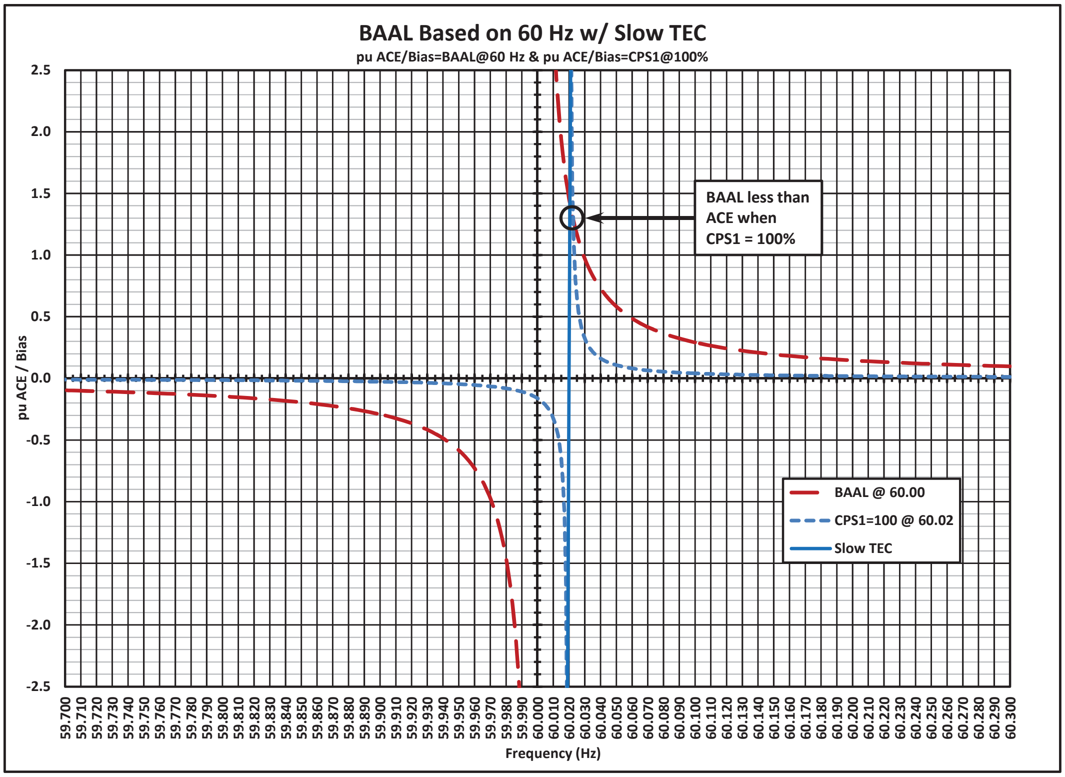

Figure 4. BAAL Based on 60 Hz w/ Slow TEC

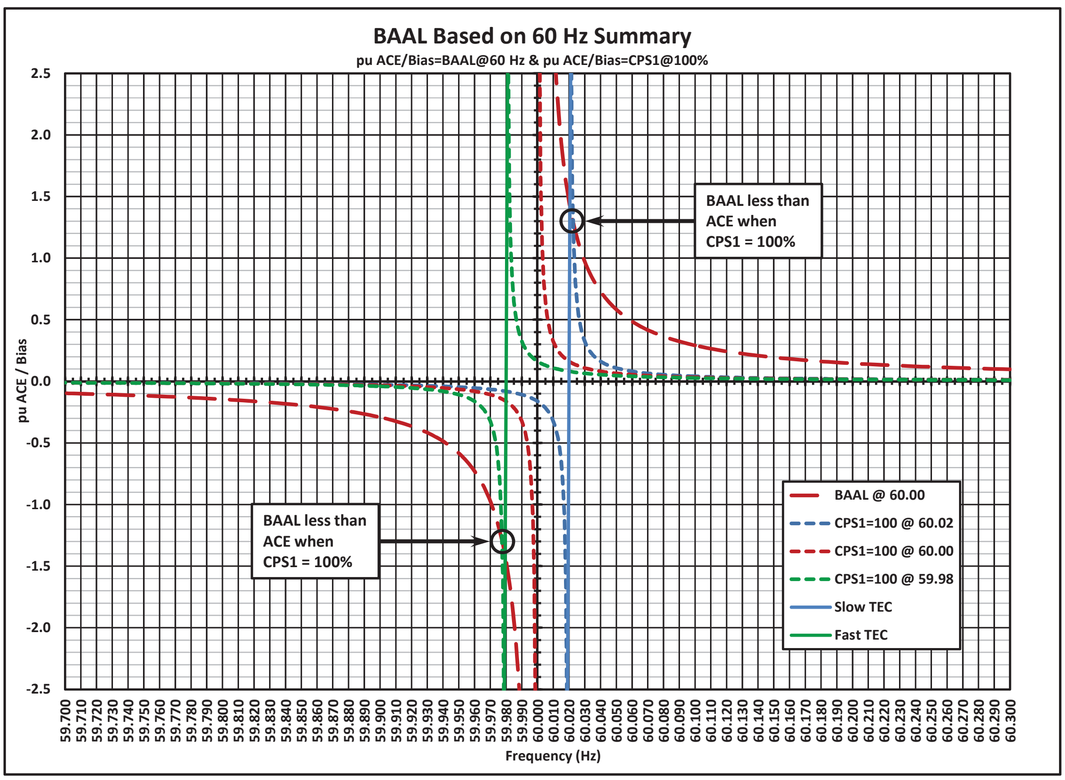

Figure 3. BAAL Based on 60 Hz Summary

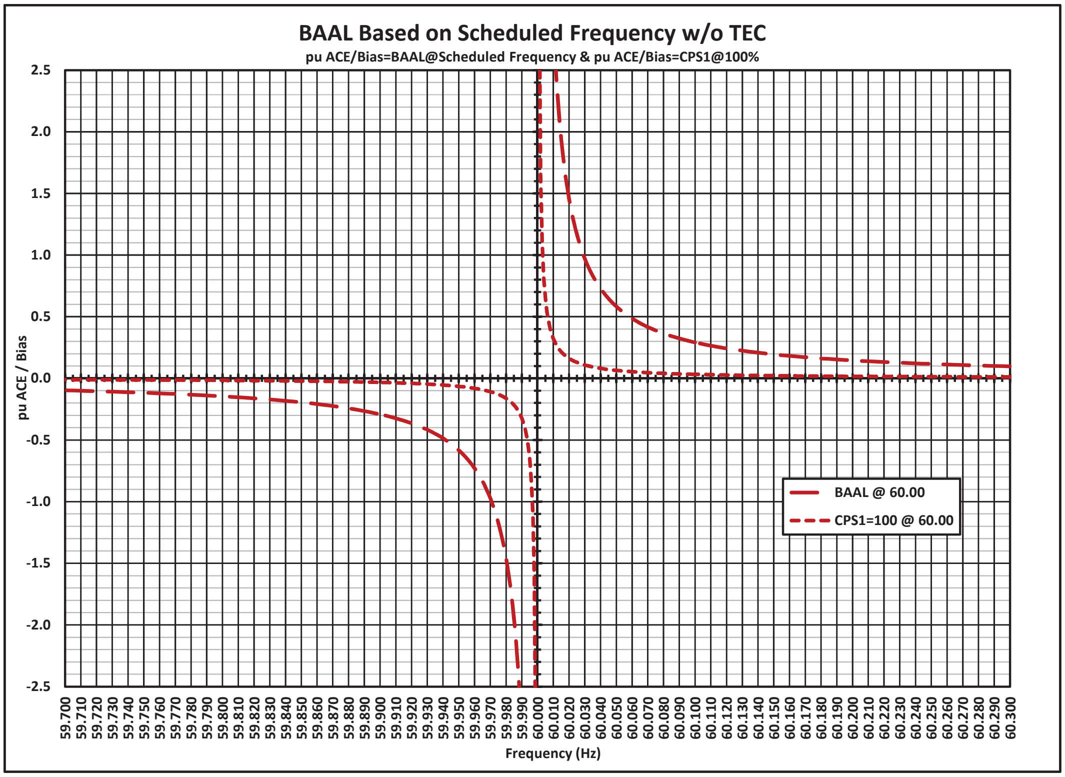

Figure 6. BAAL Based on Scheduled Frequency w/o TEC

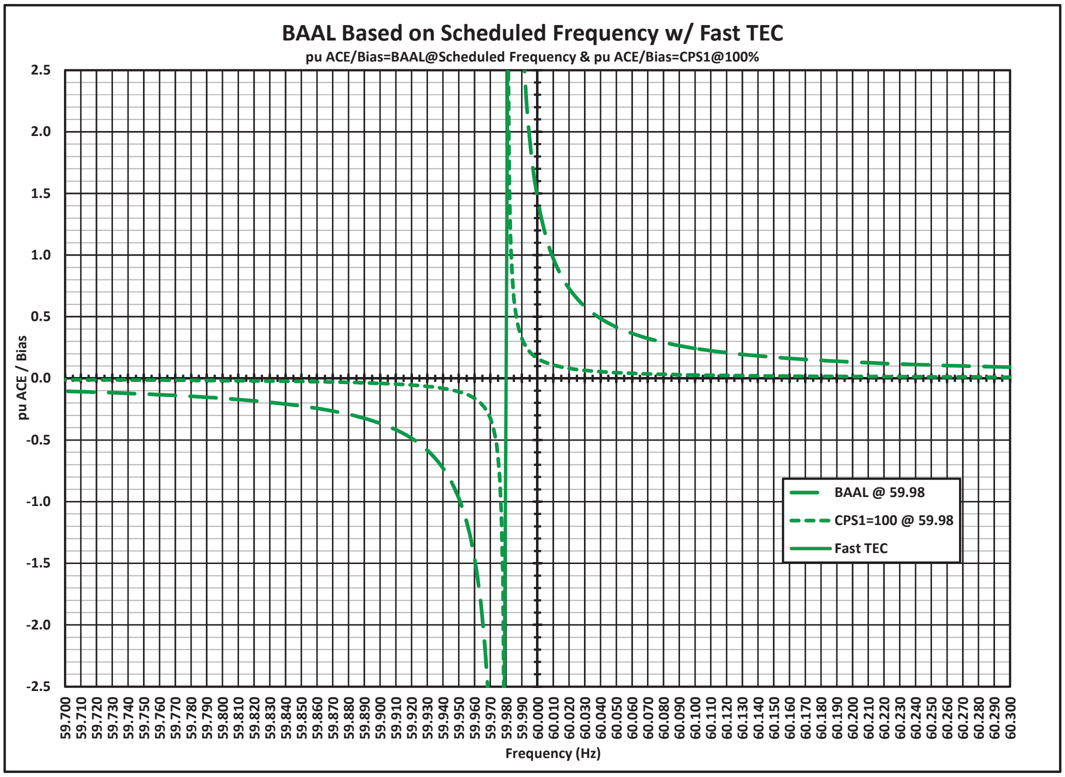

Figure 5. BAAL Based o Scheduled Frequency w/ Fast TEC

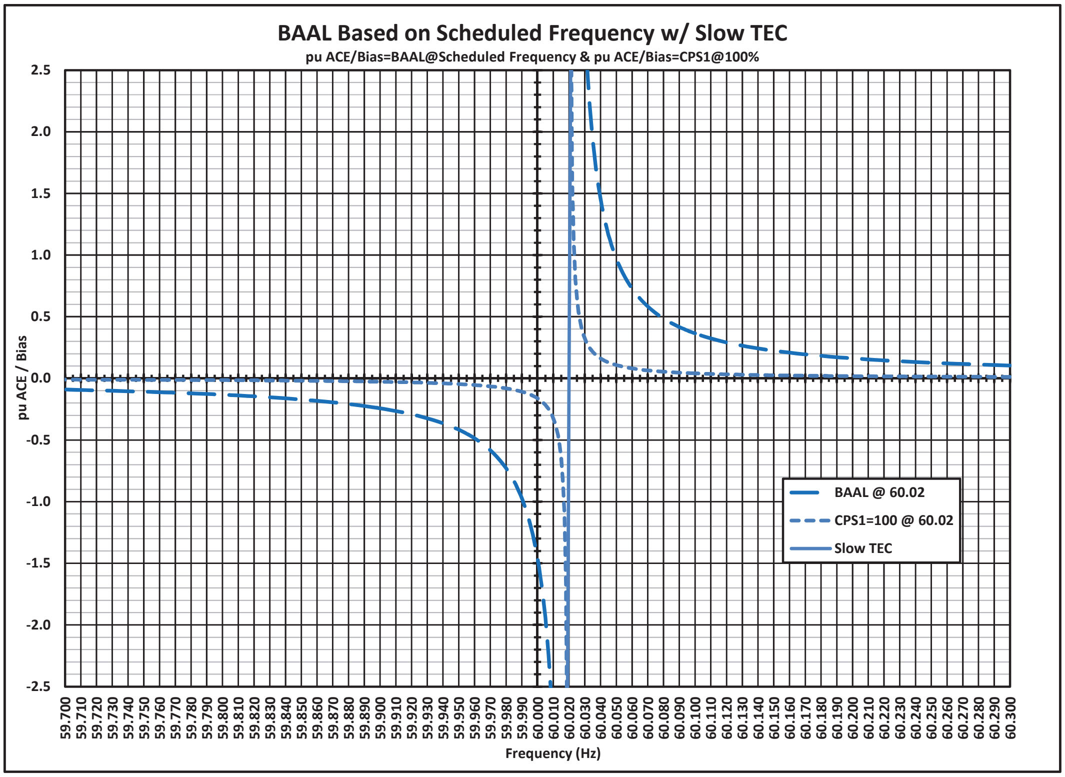

Figure 7. BAAL Based on Scheduled Frequency w/ Slow TEC

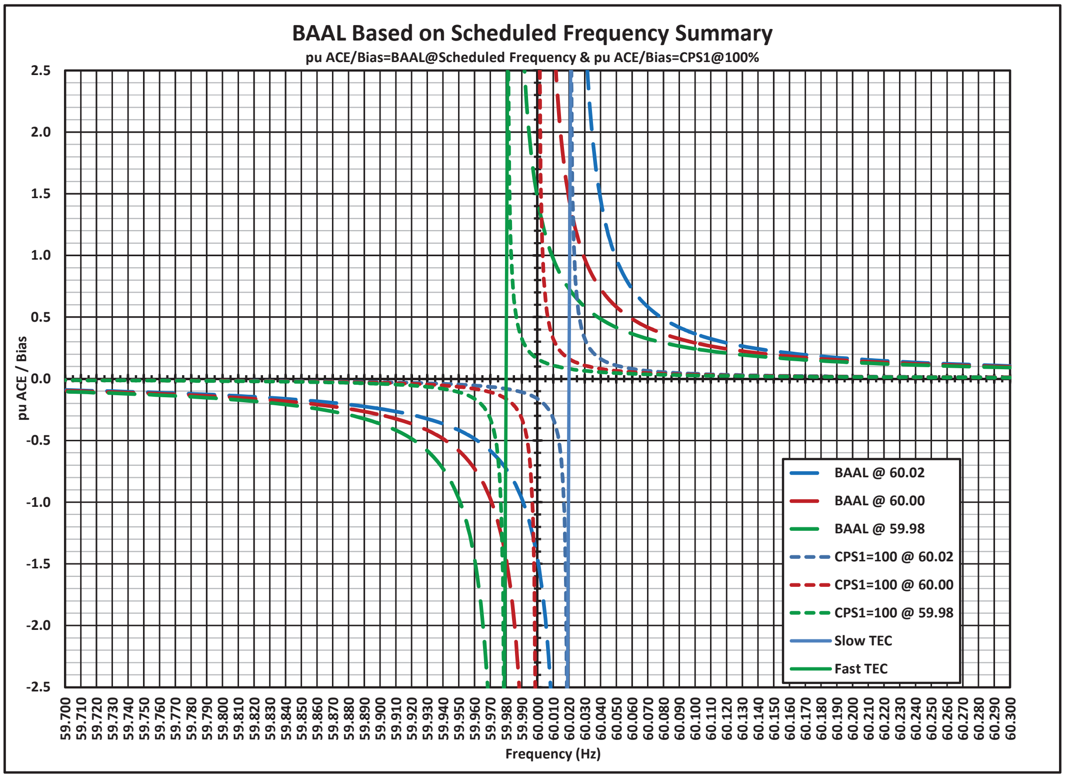

Figure 8. BAAL Based on Scheduled Frequency Summary

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-002-2 – Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

February 2013

RELIABILITY | ACCOUNTABILITY

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Atlanta, GA 30326
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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). They replaced B1 (Area Control Error (ACE) to zero in 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15-minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's most severe single contingency.

BAL-002 was created to replace portions of Policy .It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question on who is the applicable entity and assures the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 solely a performance standard. The primary objective of BAL-002-2 is to assure the applicable entity balances resources and demand and returns its Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, and the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry, however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return its Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing contingency reserve definitions primarily focused on generation and not demand side management. In order to meet FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with demand side management.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the conflict and to assure BAL-002 and EOP-002 work together and complimented each other, the drafting team clarified the existing definition of Contingency Reserve.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the
Contingency Event Recovery Period the Responsible Entity returned its ACE to:

- Zero, (if its Pre-Reportable Contingency Event ACE was positive or equal to zero),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and
  - further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

  , or
- Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and

further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable

Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entity(s) to have a clear way to demonstrate compliance and support the Interconnection to the full extent of MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for contingency reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of contingency reserve.

Additionally, R 1 is designed to assure the applicable entity must use reserve to cover a Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. Reviewing the data, the drafting team concluded, based on the median, to establish a single continent-wide standard. Thus, some interconnections may report more events and some would report less. To assure the requirements of the FERC Order No. 693 were met, the drafting team decided to capture the majority of the events having a significant impact on frequency; the reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or 500 MW.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the required contingency reserve response and measured contingency reserve response are computed and compared as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.
- The measured contingency reserve response is equal to one of the following:
  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
  - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.
- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the required contingency reserve response is greater than zero,
    - and the measured contingency reserve response is greater than or equal to the required contingency reserve response, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
    - and the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
    - and the measured contingency reserve response is less than the required contingency reserve response but greater than zero, then

the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((required contingency reserve response – measured contingency reserve response) / required contingency reserve response)).

The above computations can be expressed mathematically in the following 7 sequential steps, labeled as [1-7], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)

SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[2]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[3]**

If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 **[4]**

If REQ_CR_RESP is greater than 0, and,

MEAS_CR_RESP is greater than or equal to REQ_CR_RESP, then

COMPLIANCE = 100 **[5]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[6]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is greater than 0, and,

MEAS_CR_RESP is less than REQ_CR_RESP, then

COMPLIANCE = 100 * (1 – ((REQ_CR_RESP – MEAS_CR_RESP)/ REQ_CR_RESP)) **[7]**

Requirement 2

R2. Except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert Level 2 or 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to its Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the drafting team believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Attachment 1

NERC Interconnections 2009-2012

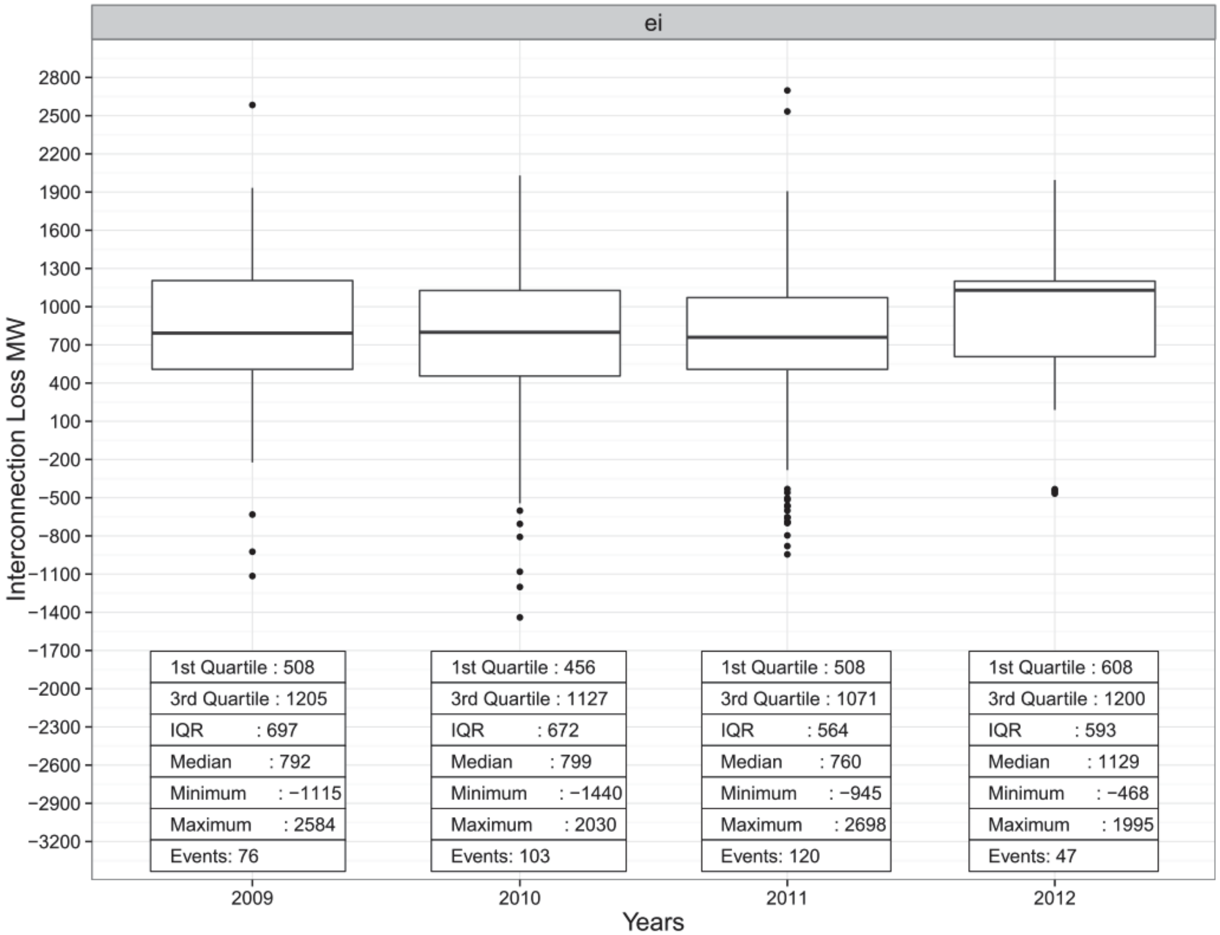
Frequency Events Loss MW Statistics

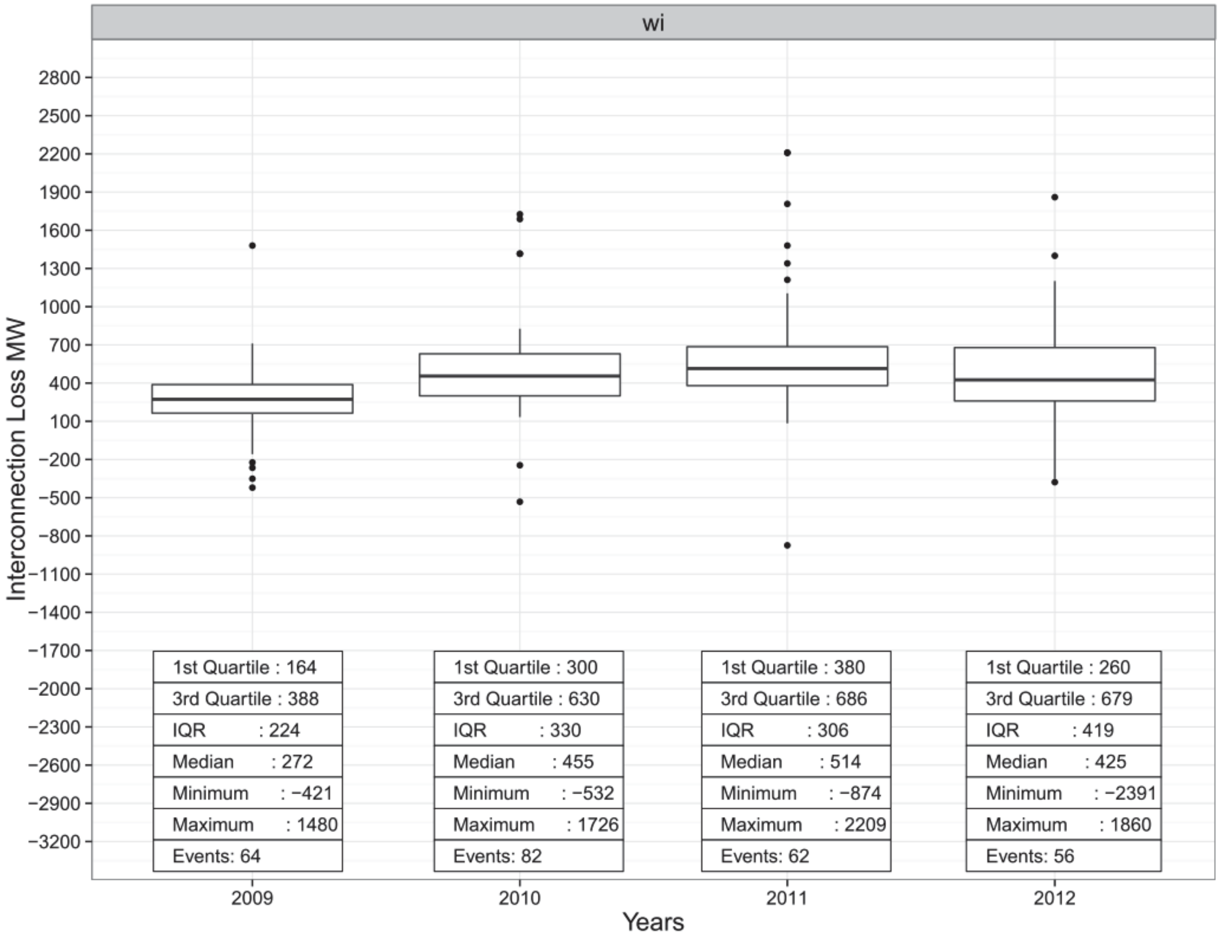
For: NERC BARC Standard Drafting Team

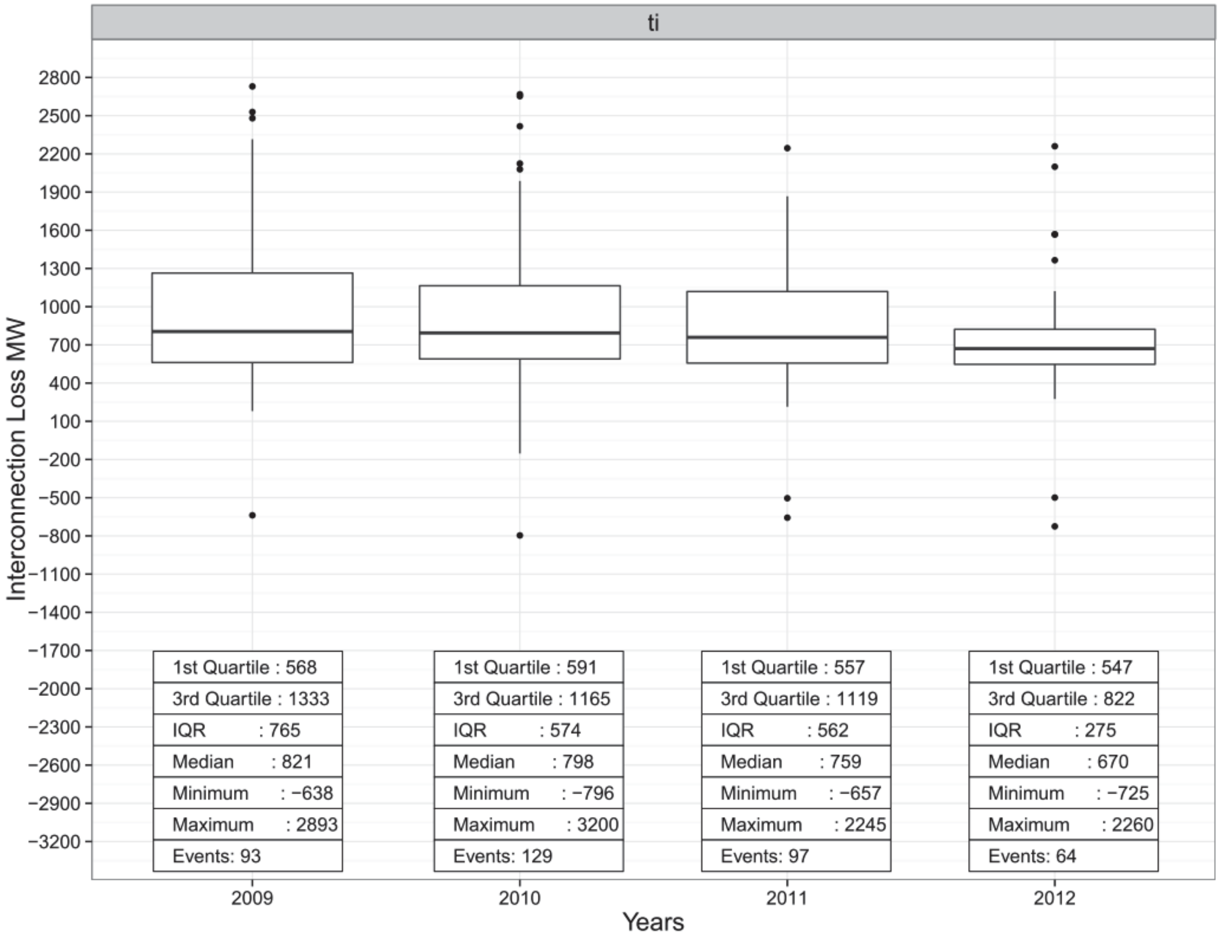
Prepared by: CERTS

Date: November 2, 2012

CERTS
Consortium for Electric Reliability Technology Solutions


ei
2800
2500
2200
1900
1600
1300
1000
700
400
100
−200
−500
−800
−1100
−1400
−1700
−2000
−2300
−2600
−2900
−3200
Interconnection Loss MW
1st Quartile : 508
3rd Quartile : 1205
IQR : 697
Median : 792
Minimum : −1115
Maximum : 2584
Events: 76
1st Quartile : 456
3rd Quartile : 1127
IQR : 672
Median : 799
Minimum : −1440
Maximum : 2030
Events: 103
1st Quartile : 508
3rd Quartile : 1071
IQR : 564
Median : 760
Minimum : −945
Maximum : 2698
Events: 120
1st Quartile : 608
3rd Quartile : 1200
IQR : 593
Median : 1129
Minimum : −468
Maximum : 1995
Events: 47
2009
2010
2011
2012
Years


wi
Interconnection Loss MW
2800
2500
2200
1900
1600
1300
1000
700
400
100
−200
−500
−800
−1100
−1400
−1700
−2000
−2300
−2600
−2900
−3200
1st Quartile : 164
3rd Quartile : 388
IQR : 224
Median : 272
Minimum : −421
Maximum : 1480
Events: 64
1st Quartile : 300
3rd Quartile : 630
IQR : 330
Median : 455
Minimum : −532
Maximum : 1726
Events: 82
1st Quartile : 380
3rd Quartile : 686
IQR : 306
Median : 514
Minimum : −874
Maximum : 2209
Events: 62
1st Quartile : 260
3rd Quartile : 679
IQR : 419
Median : 425
Minimum : −2391
Maximum : 1860
Events: 56
2009
2010
2011
2012
Years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Interconnection Loss MW
2800
2500
2200
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1600
1300
1000
700
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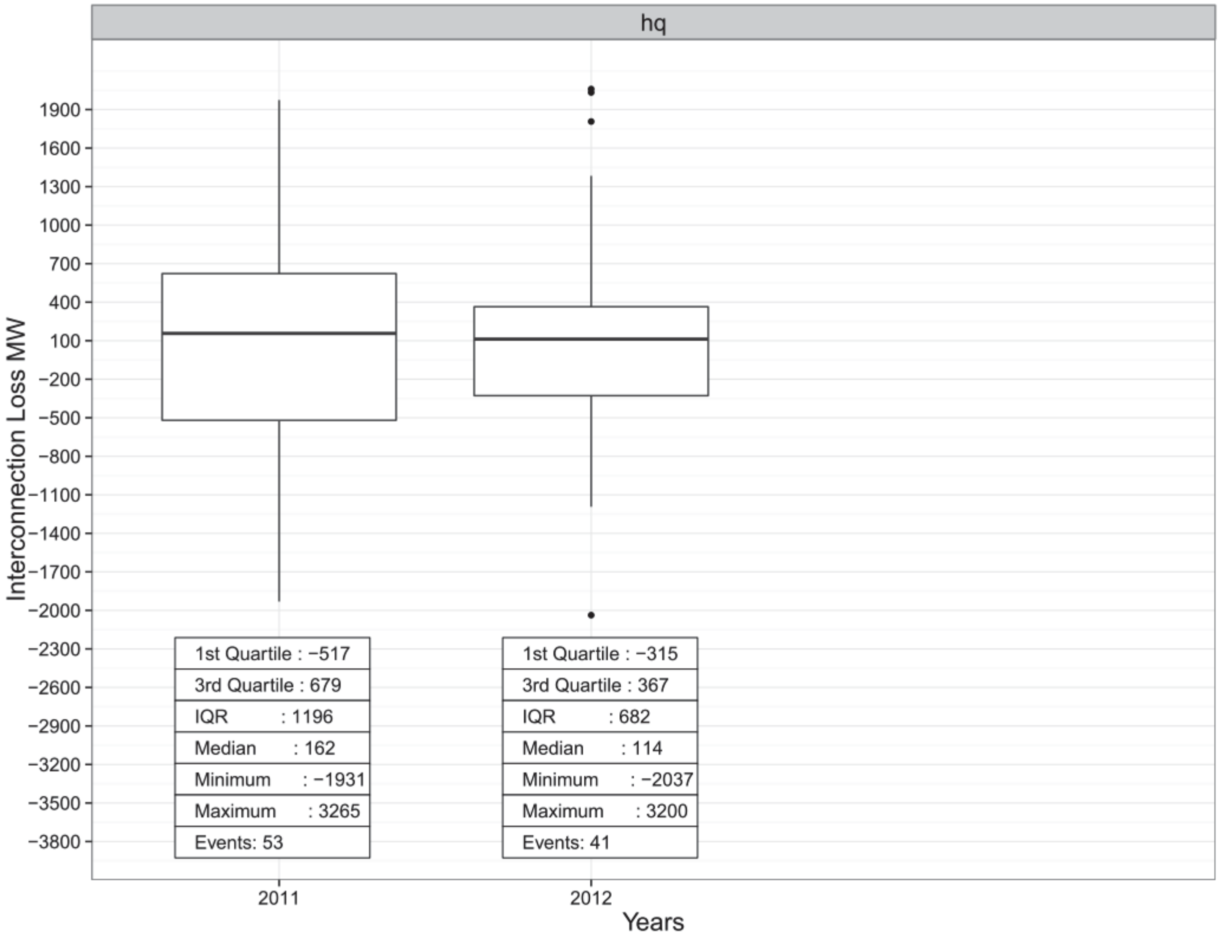
100
−200
−500
−800
−1100
−1400
−1700
−2000
−2300
−2600
−2900
−3200
1st Quartile : 568
3rd Quartile : 1333
IQR : 765
Median : 821
Minimum : −638
Maximum : 2893
Events: 93
1st Quartile : 591
3rd Quartile : 1165
IQR : 574
Median : 798
Minimum : −796
Maximum : 3200
Events: 129
1st Quartile : 557
3rd Quartile : 1119
IQR : 562
Median : 759
Minimum : −657
Maximum : 2245
Events: 97
1st Quartile : 547
3rd Quartile : 822
IQR : 275
Median : 670
Minimum : −725
Maximum : 2260
Events: 64
2009
2010
2011
2012
Years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Interconnection Loss MW
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1600
1300
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400
100
−200
−500
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−1400
−1700
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−2600
−2900
−3200
−3500
−3800
1st Quartile : −517
3rd Quartile : 679
IQR : 1196
Median : 162
Minimum : −1931
Maximum : 3265
Events: 53
1st Quartile : −315
3rd Quartile : 367
IQR : 682
Median : 114
Minimum : −2037
Maximum : 3200
Events: 41
2011
2012
Years

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. $AVG_{Period} \frac{ACE1}{-10B}$ 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}. $AVG\text{10-minute}(ACE_i) \leq L_{10}$ 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, 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.

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	Applicability 4.1. Balancing Authority 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. 4.2. Reserve Sharing Group 1.4. Additional Compliance Information The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members. R2.3. The permissible mix of	This Requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for an reliability outcome and if violated would not cause separation, instability or cascading outages.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		
R3. Each Balancing Authority or Reserve Sharing Group shall	This Requirement has been moved into BAL-002-2 Requirements R1 and	BAL-002-2 Requirement R1

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	Requirement R2	**3.** Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to: • Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		its Pre-Reportable Contingency Event ACE Value was negative): o Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. BAL-001-2 Requirement R2 **2.** Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 **1.** Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to: • Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero): O less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and O further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.		completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative): O Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and O Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. Contingency Event Recovery Period A period beginning at the time that the resource

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:	This Requirement has been moved into BAL-002-2 Requirement R1 and Reserve Sharing Group Reporting ACE	BAL-002-2 Requirement R1 **2.** Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to: • Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o further reduced by the magnitude of the

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully		difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative): o Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
implemented, and within the Disturbance Recovery Period.		Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. **Reserve Sharing Group Reporting ACE** At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that make up the Reserve Sharing Group.
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection. R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition	BAL-002-2 Requirement R1 **1.** Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to: • Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero):

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R6.2. The default Contingency Reserve Restoration Period is 90 minutes.		o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative): o Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

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

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[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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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-002-2, Contingency Reserve for Recovery from a Balancing Contingency Event. 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

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[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-002-2:
There are two requirements in BAL-002-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-002-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, proposed BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, proposed BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2 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-002-2 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-002-2 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 levels of noncompliance performance.	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 amount of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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)

-
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.

Name (32 Responses)
Organization (32 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Contact Organization (23 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (13 Responses)
Comments (55 Responses)
Question 1 (35 Responses)
Question 1 Comments (42 Responses)
Question 2 (36 Responses)
Question 2 Comments (42 Responses)
Question 3 (36 Responses)
Question 3 Comments (42 Responses)
Question 4 (35 Responses)
Question 4 Comments (42 Responses)
Question 5 (37 Responses)
Question 5 Comments (42 Responses)
Question 6 (32 Responses)
Question 6 Comments (42 Responses)
Question 7 (34 Responses)
Question 7 Comments (42 Responses)
Question 8 (32 Responses)
Question 8 Comments (42 Responses)
Question 9 (33 Responses)
Question 9 Comments (42 Responses)
Question 10 (0 Responses)
Question 10 Comments (42 Responses)

Individual
Ken Gardner
Alberta Electric System Operator
No
Please consider revising requirement R2 to use the proposed new definitions as follows: R2. Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]
Individual
Tom Siegrist
EnerVision, Inc.
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
Northeast Power Coodinating Council
Guy Zito
Northeast Power Coordinating System
Yes
No
The last sentence in the definition is not needed, and should be removed. “The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.” is the “How” to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence.
No
There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Pre-Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Yes
Yes
Yes
Yes
Yes
Yes
There isn’t an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an

adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: • recover from a Reportable Event within 15 minutes; • replenish reserves within 90 minutes.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
John Tolo
Tucson Electric Power
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
very helpful

Individual
Rich Hydzik
Avista
No
The changes to the definitions add clarity, but ambiguity still exists around one phrase. What constitutes an “unexpected change to the responsible entity’s ACE?” Does this mean that there is no human action when the ACE change occurs? Does this mean that a human action to change a Net Interchange value in the ACE equation is “unexpected” when it is due some force majeure condition? Clarity around this issue is necessary to prevent Balancing Authorities (BA) from merely adjusting their Net Schedule Interchange value to correct ACE and passing the problem on to another BA. If transmission curtailments and unexpected adjustments to e-tags are acceptable events to deploy contingency reserve and are considered “Sudden Loss of Generation” under BAL-002-2, this needs to be explicitly stated. If transmission curtailments and unexpected adjustments to e-tags are NOT acceptable events to deploy contingency reserve and are NOT considered “Sudden Loss of Generation” under BAL-002-2, this needs to be explicitly stated. The Background Document discusses frequency deviations on Page 4 under “Balancing Contingency Event.” This seems to preclude any human action to alter Net Scheduled Interchange as a “Balancing Contingency Event.”
Yes
Yes
The assumption is made that algebraic sum of the ACE’s is as follows: Reserve Sharing Group Reporting ACE = ACE(BA1) + ACE(BA2) + ACE(BA3) + …. An example calculation would be helpful and provide clarity.
Yes
This language clarifies that when in an Energy Alert 2 or 3, the BA is using all available reserves to maintain ACE.
Yes
Yes
Yes
Yes
Yes
I can support this draft standard with the clarifications requested in Question #1 above.
Individual
Nazra Gladu
Manitoba Hydro
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.

Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Yes
No comment.
Although Manitoba Hydro is in support of this standard, we have the following clarifying comments: (1) Definitions, Reportable Balancing Contingency Event – there is no definition within the standard or Glossary as to what ‘EMS scan rate data’ is. (2) Definitions, Contingency Event Recovery Period – the definition does not clearly define exactly when the Contingency Event Recovery Period begins. As written, the definition seems to indicate that this period begins at two different times (i) when the resource output begins to decline and (ii) in the first one minute interval of a Balancing Contingency Event. Please clarify. (3) 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? (4) 1. (Proposed) Effective Date in both Standard and Implementation Plan - remove the “ ‘ “ following the word ‘Trustees’ because it is not defined this way in the Glossary of Terms. (5) R1 - as written, R1 requires that the Responsible Entity demonstrate that ACE was returned to a certain value. The demonstrate aspect of the requirement seems more of a measure than a requirement. In other words, the requirement should be that the Responsible Entity return the ACE to a certain value, the measure is that they provide evidence to demonstrate that they did so. (6) R1, R2 – both ‘MSSC’ and ‘Most Severe Single Contingency (MSSC)’ are used throughout the standard. The words ‘Most Severe Single Contingency (MSSC)’ should be used at the first instance and then the acronym ‘MSSC’ for all instances thereafter. (7) R2 – some of the terminology appears to be incorrect within this requirement. Is ‘Disturbance Recovery Period’ meant to be ‘Contingency Event Recovery Period’? Is ‘Contingency Reserve Recovery Period’ meant to be ‘Contingency Reserve Restoration Period’? (8) M1 – the word ‘including’ should be replaced with ‘as well as’ if the ‘additional documentation’ that needs to be provided is in addition to the CR Form 1, not that the additional documentation forms part of the CR Form 1. (9) VRF/VSL - capitalize ‘bulk electric system’ in both the High Risk Requirement and Medium Risk Requirement sections. (10) VSL, R1 – the language of the VSL does not track the language of the requirement or measure. The VSL refers to ‘recovering from an event’ while the requirement refers to returning ACE to a certain level. (11) VSL, R2 – the language of the VSL does not track the language of the requirement or measure. The VSL refers to calendar quarters, while the requirement and measure do not.
Group
Salt River Project
Bob Steiger
Electric Reliability Compliance
Yes
Yes
This standard is a big improvement over the existing standard because it provides much needed formal definitions of many terms that are used but not currently defined in BAL-002-1, the definition of Contingency Event, Contingency Reserve and MSSC being three of them.
Yes
Same comment as for #2.
Yes

Yes
Yes
Yes
Yes
Yes
Group
PacifiCorp
Ryan Millard
PacifiCorp
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Rich Salgo
NV Energy
No
Inclusion of “Sudden loss of a known load” is at odds with the Contingency Reserve definition, especially in light of the fact that loss of load cause ACE to increase (become more positive). In other words, why would one carry reserves to handle a decrease in load? It’s illogical. What the SDT may be trying to reference is the use of interruptible load as a type or reserve. As such, load should not be in the Contingency Event definition.
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
The Reportable Balancing Contingency Event definition lacks clarity. Are we to choose the higher of 500 MW vs. 80% of the MSSC or the lower of 500 MW vs. 80% of the MSSC? Seems like the measurement should be the higher of the two. 2. While I think I understand the goal of R1, to return ACE to zero neglecting other contingency events within the recovery period, the wording is very confusing. Expect misapplication of the standard with the existing wording. I suggest, for bullet #2: • Its Pre-Reportable Contingency Event ACE, (if its Pre-Reportable Contingency Event ACE was negative), o less the Balancing Contingency Events' magnitude summation for all subsequent events occurring within the Contingency Event Recovery Period, and o If the contingency event is greater than MSSC, further reduce the ACE recovery magnitude by difference between the Responsible Entity's MSSC and the uncompleted Balancing Contingency Events' magnitude summation.
Group
MRO NERC Standards Review Forum
Russel Mountjoy-Secretary
MRO
No
The presently approved NERC definition for contingency seems adequate for this standard. If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Yes
No
All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
No
This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. Please clarify. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Please clarify. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to

embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. Is the SDT stating that recovery is needed to recover to zero or MSSC? We believe the way a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
No
We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Yes
No
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
There first needs to be agreement on the requirements before there is concurrence with the background document.
Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today’s DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team’s SAR and the Order No. 693 directives. Recommend that each interconnection has a different MW level, due to the sheer size of each interconnection. As an Eastern Interconnection entity, we recommend 900 MW vise 500 MWs. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendations are: • Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). • Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. • Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. • The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA’s performance approaches non-compliance. The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority. The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination

of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by the NSRF, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. The NSRF is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.
Individual
Anthony Jablonski
ReliabilityFirst
No
a. ReliabilityFirst recommends removing any references to “an Energy Emergency Alert Level 2 or Level 3” since these are not defined terms (Energy Emergency Alert Levels are only noted in Attachment 1, EOP-002-3). ReliabilityFirst believes the BAL-002-2 should stand on its own merit and not rely on conditions within an attachment within another standard. For example, if the Energy Emergency Alert levels designations ever change in the future, this has the potential to have an impact on the intent of the BAL-002-2 standard. For consideration, ReliabilityFirst recommends defining the alert levels within the standard itself as an attachment, hence not relying on another standard for these conditions.
No
The VSLs for Requirement R2 references “each calendar quarter” while the actual requirement R2 does not require maintaining an amount of Contingency Reserve at least equal to its Most Severe Single Contingency on a quarterly basis. Also, the lower VSL starts with an entity being deficient for more than five hours. This poses a gap; if for example, an entity was deficient between one and four hours. ReliabilityFirst recommends restructuring the VSLs, to be consistent with the language in the requirement, as follows (this is an example of a Lower VSL); “The Responsible Entity maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency but its Contingency Reserve was deficient for less than or equal to 15 hours.”
ReliabilityFirst votes in the negative for this standards and offers the following for consideration: 1. Definition of Reportable Balancing Contingency Event: ReliabilityFirst does not agree with the inclusion of last sentence (i.e., The 80% threshold may be reduced upon written notification to the Regional Entity) within the definition. As written, the definition infers that there is an expectation that a Regional Entity may have to make a determination on whether to accept a reduction in the 80% threshold based upon the written notification. This is troublesome in two ways. One, this is written more like a requirement, though it is actually contained within a definition. Two, standards should not be written with expectation placed upon a non-registered entity (i.e., the Regional Entity). ReliabilityFirst recommends removing this last sentence and any reference to the Regional Entity. 2. Applicability Section - ReliabilityFirst recommends removing the paragraph stating “Applicability is determined on an individual event basis…” from the Applicability section. The Applicability section should state the functional entity that is required to comply with the standard and the requirements should state any conditions necessary to achieve the action or outcome.
Individual
Joe Tarantino
SMUD

Yes
Yes
Yes
Yes
Yes
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
Midwest ISO
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
No
We would suggest incorporating the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. For example in Subsection A, we would propose: 'Sudden, unexpected loss of generation…' Similar changes need to be made to Subsections B and C. Also, there is a timing element associated with Subsection B which could cause conflict with the wording in B. Requiring a sudden loss of import by the loss of a transmission element, implies that the loss of import would be sudden. It may or may not be. It depends on when the loss is reflected in schedules. Additionally, an entity may not know that the loss is due to a loss of transmission. We would suggest: 'Sudden, unexpected loss of an import that causes a change to the responsible entity's ACE.' In Subsection C we suggest: 'Sudden unexpected loss of a known load…' The term 'responsible entity' is not capitalized in the definition but is in the standard. Should it be in the definition?
No
As written there is no distinction as to whether 'unloaded generation' is on-line or off-line generation. Which is it, or is it both? Additional clarification here would be helpful.
No
Do you need to add '…at the time of the measurement' at the end of the definition?
Yes
Yes
Yes
Yes

No
Change all of the R1 VSLs to read 'The Responsible Entity partially recovered...'
No
We offer the following suggestions: Page 3 1st paragraph 2nd line – replace 'They' with 'It' 4th line – remove the hyphen in '15-minute' 2nd paragraph 1st line – remove space following 'Policy' and insert space after the period Page 4 1st paragraph under Contingency Reserve 2nd line – replace 'its' with 'their' 6th & 7th lines – be consistent with the hyphens in demand side management Page 5 Correct the text formatting for Requirement 1 Page 6 2nd paragraph Capitalize Contingency Reserve 3rd paragraph 1st line – delete space in R1 5th paragraph Reword the 2nd sentence to read: 'Reviewing the data, the drafting team decided to establish a single, continent-wide standard on the median value of generation loss.' Under Violation Severity Levels This needs to be rewritten. The VSLs are based solely on amount of recovery. The paragraph tries to include the sufficiency of response but it's not in the VSLs. Page 10 Last paragraph Needs to be rewritten; what's there refers to R1 not R2.
Individual
Greg Travis
Idaho Power Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
We generally agree with the revised definition, but do not see the need for the last sentence: "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." This is the "How's" to meet the contingency reserve requirement, which does not belong to a definition. We suggest to remove this sentence.
No
We do not see the need to define the term Reserve Sharing Group Reporting ACE. This term is not

referenced or used in the standard at all. On the other hand, if the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Pre-Reportable Contingency Event value, then the standard is not explicit or complete to place this obligation on the RSG.
Yes
Yes
Yes
Yes
Yes
Yes
We will support this standard, however please note the concerns expressed under Q2 and Q3, above, namely: a. The last sentence in the definition for Contingency Reserve, and b. The need to define the term Reserve Sharing Group Reporting ACE (or the lack of explicit requirement for RSG to meet the DCS requirement).
Individual
Howard F. Illian
Energy Mark, Inc.
No
The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Yes
No
The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Yes
No
I believe that this requirement falls under Paragraph 81 and should not be in the standard.
Yes
Yes
Yes
Yes
The definition of "Pre-reportable Contingency Event ACE Value" should be modified as follows: The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is. I would strongly suggest that the wording for Requirement 1 should be modified to read as follows: R1. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its Reportable ACE to: [Violation Risk Factor: Medium][Time Horizon: Real-time Operations] • Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero): o less the

sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.
Group
SERC OC Standards Review Group
Stuart Goza
Tennessee Valley Authority
Yes
Yes
No
The definition should only include the BAs that were participating in the event.
Yes
No
This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We agree with the principle of a BA maintaining contingency reserves to respond to its MSSC. However, as R2 is currently proposed it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures and VSL, we believe that the requirement needs to stand on its own and that the specifying language should be included in R2 itself.
No

It is difficult to agree with the VRF's while disagreeing with the standard as proposed.
Yes
No
Requirement 1 should not be an event by event obligation. A quarterly average measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believe that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the Background Document relating to the methodology for development of the reporting thresholds.
There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection. We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a

consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly – ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high – why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply. These comments were also supporteed 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.
Group
seattle city light
paul haase
seattle city light
No
Seattle City Light considers the definition of Balancing Contingency Event proposed in this draft of BAL-002-2 to be incomplete in that it does not recognize the failure of a unit to start as an "event." Seattle recommends revising the definition to read: "A.a.i. Unit Tripping or failure to start at the scheduled time."
Yes
Yes
Note there are differing reference to Regulating Reserve Sharing Group and Reserve Sharing Group BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the standards.
Yes
This standard is an improvement over the existing BAL-002 because it clarifies the requirements for a Balancing Authority or Reserve Sharing Group regarding Contingency Reserve requirements during Energy Emergency Alerts.
No
Seattle City Light finds Requirement R2 and Measure M2 to lack specificity as to what level of performance is required for compliance, and recommends the following changes: "R2. Each Responsible Entity shall maintain an amount of Contingency Reserve such that its clock-minute average of Contingency Reserves is equal or greater than the Most Severe Single Contingency except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert 2 or 3." "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 hard copy or electronic format) to demonstrate compliance with Requirement R2."
Yes
Yes

Yes
Seattle City Light supports the general concepts of this draft of BAL-002-2, but as with BAL-001-2, Seattle thinks this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Several specific recommendations for changes have been noted above. However, at least until the Guidelines document is available that details how this Standard will work in conjunction with other BAL Standards, Seattle cannot support this draft.
Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Group
PJM Interconnection, LLC
Stephanie Monzon
Stephanie Monzon
Yes
Yes
No
The definition should only include the BA’s participating in the event.
No
PJM agrees with the principle of a BA maintaining contingency reserves to respond to its MSSC but believe this requirement would have negative unintended consequences. Reserves should be used when there is a reliability need that may or may not be caused by the loss of a resource. This requirement encourages BA’s to withhold deployment of contingency reserves except for DCS reportable disturbances. For example, if a BA’s ACE is dragging into the top of the hour, along with Interconnection frequency, due to schedule changes and slow unit response, this requirement incentivizes the BA to withhold deploying reserves. If a BA is approaching an IROL that could be mitigated by deploying contingency reserves, this requirement penalizes the BA for doing so, even though the result would benefit the Interconnection. Even if PJM agreed with the proposed R2, which we do not, as written it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures, specifically M2, PJM believes that the requirement needs to stand on its own and that the specifying language should be included in R2 itself. DCS performance in North America has been greatly improved compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commission’s directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process, as was a directive in 693), NERC could add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data”.
Yes
No

It is difficult to agree with the VSL's while disagreeing with the standard as proposed.
No
The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." PJM disagrees with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. PJM believes that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample, skewing the results. PJM believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.
In R1 and R2, delete the language related to a Responsible Entity under an Energy Emergency Alert Level 2 or Level 3, for the following reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. PJM appreciates the SDT's goal of drafting a continent-wide standard but disagrees with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, PJM believes that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500MW as an example, a loss of 500MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. PJM believes that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared annually by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection (ALR1-12 Assessment). As previously stated, PJM respectfully suggests that the SDT give due consideration to redefining a Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. PJM believes this is one approach that could satisfy the directive set forth in Order 693.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Agree
ERCOT

Individual
Angela P Gaines
Portland General Electric Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Portland General Eletric is supportive of this standard.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
No
The last sentence in the definition is not needed, and should be removed. “The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.” is the “How” to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence. Because of the nature of using hourly integrated values, Requirement R2 may not provide Operators on shift with sufficient information in a timely manner. We recommend an alternative that uses a timer that begins to count up when the BA becomes deficient in contingency reserve, resulting in a compliance violation should the condition persist for 105 minutes. Also, as proposed, it may be create burdensome reporting requirements so that an hourly shortfall can be dismissed due to Balancing Contingency Events, for example.
No
There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Pre-Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Yes
Yes
Yes

Yes
Yes
There isn’t an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: • recover from a Reportable Event within 15 minutes; • replenish reserves within 90 minutes. As written, the Standard is overly complex.
Individual
Thad Ness
American Electric Power
Yes
No
It is not clear exactly what “other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3)” refers to.
Yes
No
Please see our response to Q2 in regards to the definition of Contingency Reserve. AEP disagrees with the second half of R1 where it begins with “or… Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative)…” . The language provided in this section and its sub-bullets are extremely confusing. It appears that the intent is to set an expectation for recovering from multiple contingency events, however the language provided is unnecessarily complex and will likely confuse those responsible for meeting the requirements.
Yes
Yes
Yes
Yes
No
It is unclear whether or not the guidance document will eventually become a part of the officially posted standard (in an appendix for example).
In addition to the comments provided to the earlier questions above, AEP offers the following additional comments for consideration. AEP disagrees with the latest proposed definition of “Pre-Reportable Contingency Event ACE Value”, which has been made ambiguous by the most recent modifications. What is the intent of the drafting team in modifying the definition in this way? If this definition were to be used, new tools would likely need to be developed in order to calculate the value in this manner, as the operators would now be required to continuously calculate the ACE value based on this new definition. The definition for, and application of, Contingency Event Recovery Period is unnecessarily complex, confusing, and likely unpractical in its application. For example, if a unit was taken out of service due to a controlled shut-down, the Real Time Operator’s most pressing responsibility is balancing load and generation. Requiring this person to use the proposed methodology to determine exactly the contingency event recovery period began would distract the Real Time Operator from their core balancing responsibilities. Rather than take this approach, we

recommend retaining the existing way of determining when the recovery period begins, which is a more straightforward and reasonable approach. In addition, the definitions for Contingency Event Recovery Period and Contingency Reserve Restoration Period are quite similar and would most likely prove confusing to industry in their application. Taking a conditional-based approach across multiple standards does not serve the reliability of the bulk electric system, as it takes a straightforward concept, overly complicates it, and distracts Real Time Operators from the core reliability objectives.
Group
Duke Energy
Greg Rowland
Duke Energy
No
• The definition is too broad. Using the phrase “or any series of such otherwise single events” leaves much open to interpretation. In many cases it will not be clear when the 15-minute clock has been triggered. • Regarding Subsection “C.”, it is also not clear what is meant by the “sudden loss of a known load used as a resource”. Is the team referring to an interruptible load resource, fully loaded and counted on for provision of contingency reserve? If so, would the sudden loss of the resource mean that the load is inadvertently interrupted causing high ACE? We’re not aware of a proven reliability risk that warrants a 15-minute recovery period from a high ACE. Or, is the team referring to an interruptible load resource already implemented (curtailed) for a first contingency, and then somehow losing the curtailment capability where the resource fully loads again causing low ACE (second contingency)? If so, has any such event ever been documented to warrant placing a statement subject to interpretation in the Standard? • Duke Energy suggests striking Subsection “C.”, as loss of any load is covered under the BAAL in BAL-001-2. • Based upon the above, Duke Energy suggests revising the definition to – “Balancing Contingency Event: Any single event described in Subsection (A) or (B) below, or any combination of those events occurring within less than one minute.” Duke Energy suggests revising Subsection “A.b” to read “And, that causes an unexpected negative change to the responsible entity’s ACE”, and suggests revising Subsection “B” to state “Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected negative change to the responsible entity’s ACE.” Both changes are suggested to clarify that this standard is applicable to the loss of resource causing an unexpected drop in ACE. To the extent that Subsection “C” is retained, Duke Energy suggests a similar revision to insert the word “negative”.
No
We would be in agreement except that it includes the term “Balancing Contingency Event”, and we would need our above suggested changes made to that definition to be in agreement here.
No
Only BA’s participating in response to an event should be included in the Reserve Sharing Group Reporting ACE calculation. As we commented on BAL-001-2, ACE should be fully defined in a manner where Reporting ACE can be defined simply as the “The scan rate values of a Balancing Authority’s ACE”.
Yes
We agree with the change to R1 to recognize emergency operations as long as the BAAL is implemented in BAL-001-2, as it is the only viable standard for measuring real-time performance and the BA’s impact on Interconnection frequency during such operation. Duke Energy agrees that the proposed language in this standard will allow the BA to utilize its contingency reserves to continue to serve load under an Energy Emergency Alert Level 2 or Level 3 while remaining compliant to BAL-002; however under what circumstances, if any, should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to Requirement R1 under normal operations? In our opinion, the inability of a Balancing Authority to meet the 15-minute DCS compliance threshold does not in itself represent a reliability issue. There are cases in the off-peak times especially where the recovery is detrimental to Interconnection frequency. Some of the revisions in BAL-002-2 blur the clear and well-established criteria of what triggers the DCS event. Too much is left up to after-the fact compliance scrutiny, and operators need unquestionable guidance on this matter. Also, in the definition of Contingency Reserve, add the word “NERC” before the word “contingency” for clarity.

No
Requirement R1 and R2 could provide a consistent continent-wide Contingency Reserve policy if the definition of Balancing Contingency Event provided a “bright line” to the industry on what events would be applicable to the determination of MSSC; we believe that Subsection “C.” of that definition should be deleted, per our comment under question #1 above, and if the R2 allowed for other use of Contingency Reserves. Requirement 2 refers to “Disturbance Recovery Period” and “Contingency Reserve Recovery Period” which are no longer defined. Duke Energy would suggest the following change: “Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an hourly average amount of Contingency Reserve at least equal to its Most Severe Single Contingency.” Language in Requirement R2 should also recognize that Contingency Reserves may be used from time to time to aid in balancing aside from the loss of resource – today such use takes places and does not impact compliance under DCS. Measure M2 requires that the Contingency Reserve averaged over each clock hour is greater than or equal to the amounts identified in Requirement 2 – however, as the amounts identified in Requirement R2 are allowed to be less than MSSC, it is not clear why the language at the end places an exception only on the 105-minute combined recovery and restoration period, and not on any period such resources may be utilized under an EEA2 or EEA3. Duke Energy would suggest modifying Measure M2 to read at the end “except during an Energy Emergency Alert Level 2 or Level 3, or within the first 105 minutes following an event requiring the activation of Contingency Reserve.” Though an hourly average is proposed, it is not practical for a BA to track its Contingency Reserves in a manner where it would make the choice to increase its Contingency Reserves above the MSSC if it happened to drop below its MSSC for some time in the same hour – it is an unnecessary activity to bring into real-time operations. Also, we believe the Standard Drafting Team should carefully check to make certain that these new definitions don’t impact other existing definitions. Though suggestions have been provided, Duke Energy does not support the adoption of Requirement R2 and agrees with the comments provided by MISO. Performance under the existing BAL-002 has been stellar without the need for an additional requirement to track Contingency Reserves to the extent prescribed. The current DCS is a very effective results-based standard. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability.
No
We can’t agree, due to the current lack of clarity in the requirements.
Yes
No
We can’t agree, due to the current lack of clarity in the requirements.
• As the BAAL proposed in BAL-001-2 will address the loss of any resource, or any other change in ACE causing a Balancing Authority to exceed its BAAL, it could be argued that there is no reliability need to retain DCS. In 2007, the NERC Operating Committee supported the adoption of the BAAL and a subsequent field trial of operating without DCS to determine if the Standard was still needed. Until more experience is gained under the BAAL, Duke Energy supports having a Standard driving a Balancing Authority to address the largest of its events as it does today, however we see no reliability need to expand BAL-002 beyond the simple concept of measuring the recovery to the largest of the BA’s resource losses – 80% or greater of the MSSC, and limited to MSSC, where the applicable events are clearly understood by the operator. Duke Energy disagrees with applying compliance and associated compliance reporting on an event-by-event basis, rather than allowing the quarterly reporting currently provided under BAL-002. The measures for compliance should recognize that no technical basis has been provided to support the 15-minute recovery required under Requirement R1 – compliance to a line drawn in the sand can be measured on a quarterly basis similar to today, as real-time reliability needs will be met by the BA being held to compliance under BAAL. • Duke Energy disagrees with the definition of “Reportable Balancing Contingency Event”. Given that all resource losses will be captured by the BAAL under BAL-001-2, that there is no basis for using 500 MW as a baseline for reporting, and that there has not been a demonstrated reliability need to move away from our current reporting criteria of 80% or greater of the MSSC, Duke Energy does not support the

inclusion of the 500 MW threshold in the definition.. We believe that BAAL 30-minute response covers all events, and DCS action is a 15-minute response intended to address large events. We agree with MISO's comment that currently DCS is measured quarterly, and the proposed Requirement R1 creates an unnecessary event-by-event compliance evaluation. Adding the 500 MW threshold and multi-contingent event expectation is excessive, with no benefit to reliability. • Duke Energy believes that Reserve Sharing Group should have the flexibility to calculate a group ACE rather than just taking the algebraic sum of all the BA ACEs.
Individual
John Seelke
Public Service Enterprise Group
Agree
PJm Interconection
Group
DTE Electric
Kent Kujala
DTE Electric
Agree
MISO
Individual
Keith Morisette
Tacoma Power
No
Tacoma Power is unfamiliar with the phrase, "... known load used as a resource ..." We believe the industry cannot interpret these words consistently. Instead, we suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation.
Yes
Yes
Yes
Yes
Yes
Yes
No
Tacoma Power does not understand - all levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100% in every case? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.
Yes
Tacoma Power appreciates the opportunity to provide comments. We cannot support this draft of the standard because we are unfamiliar with the phrase, "... known load used as a resource ..." in the definition of a Balancing Contingency Event. Therefore, this phrase must be defined or replaced so that there is no confusion within the industry and compliance authorities. We suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation. In addition, the VSLs are very confusing. All levels state that the Responsible Entity

recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be “recovered” without reaching 100%? Instead, we suggest that the VSLs recognize that the Responsible Entity “partially recovered” from the event.
Individual
Don Jones
Texas Reliability Entity
Yes
Definition of “Balancing Contingency Event” is slightly different in Implementation Plan as compared to Standard (A.a.iii. Facility vs Facilities, B. Import vs import…). Definition of “Reportable Balancing Contingency Event ” is different in Implementation plan as compared to Standard (Implementation Plan does not include phrase “The 80% threshold may be reduced upon written notification to the Regional Entity.”) The Applicability section in the Implementation Plan is also different than the Standard.
Yes
The Contingency Reserve definition should mention a Reserve Sharing Group in addition to a BA.
Yes
Yes
R2- Disturbance Recovery Period is not defined and should be changed to Contingency Event Recovery Period.
Yes
A Responsible Entity may have an internal Contingency Reserve policy that is different than the proposed language in R2. While we understand the R2 states the minimum Contingency Reserve amount, should R2 be re-worded to state that each Responsible Entity shall maintain an amount of Contingency Reserve as least equal to its Most Severe Single Contingency or an amount per its Contingency Reserve policy, whichever is larger? Ex. The MSSC in ERCOT is 1375 MW, but the required minimum responsive reserve is 2300 MW, which is the amount necessary to maintain adequate primary frequency response to meet the intent of the BAL-003 standard.
Yes
Yes
No
1) R1 VSL- At what point is the ACE measured in order to determine the % of required recovery. We assume it is the lowest ACE value measured during the one-minute period for the Balancing Contingency Event, but this should be clarified. 2) R2 VSL – A deficiency less than 5 hours is not covered by the VSL. If the intent is to allow a certain amount of deficiency without penalty, that should be clearly stated in the requirement and not implied in the VSL. 3) R2 VSL – Five hours in a calendar quarter of not having sufficient Contingency Reserves seems too long, especially since Contingency Event Recovery Periods and EEAs are excluded. We would recommend a shorter time frame, e.g. 0-3 hours for lower VSL, 3-5 for moderate VSL, 5-10 for high VSL, and >10 for severe VSL. Also, the time frame for each VSL level needs to state if it is cumulative or on a per-event basis (we assume it is cumulative but it should be explicitly stated).
No
The equations and methodology on CR Form 1 seem flawed. The recovery requirement in R1 is based on ACE, but the calculations in CR Form 1 are based on the MW lost. We believe the equations in CR Form 1 and the Background Document should be modified to incorporate the elements of the ACE equation into the calculations (i.e. frequency deviation and frequency bias in particular). For example, a recent unit trip of 1300 MW occurred. Based on the frequency deviation, the lowest ACE during the one-minute event period was -1900 MW. The language of the requirement and the CR Form 1 should reflect the recovery of the ACE (1900 MW) rather than the MW lost (1300 MW) in this case.
1) In ERCOT, we have an existing process in place to analyze unit trips greater than 500MW.

However, other interconnections may find it overly burdensome to analyze these unit trips based on their current size and loads. 2) R1, as stated, is an event-by-event obligation. A failure to recover for one event would constitute a violation, even though the Responsible Entity may have performed well for the remainder of the period. Is this the intent of the SDT? Would the SDT consider another measure, such as evaluation of multiple events on a quarterly basis? 3) Does the SDT intend to retire the existing “Disturbance Control Standard” definition? Do you need to modify definition of “Reserve Sharing Group” to not reflect usage of “Disturbance Control Performance”? 4) The Reserve Sharing Group Reporting ACE definition is different here than the Regulation Reserve Sharing Group Reporting ACE definition provided in BAL-001-2, which is correct? (i.e. Does not have “at the time of measurement” as last part of sentence). 5) How do you calculate a Reserve Sharing Group Pre-Reportable Contingency Event ACE Value? We assume it is the algebraic sum of the ACEs of the BAs that make up the Reserve Sharing Group, but it may need to be explicitly stated.
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Agree
SERC OC Standards Review Group
Individual
Brian Murphy
NextEra Energy
Have the option also calculate ACE using the following formula: ACE = (NIA – NIS) – 10B (FA – FS) – IME
Individual
Robert Blohm
Keen Resources Ltd.
Yes
No

The definition is left vague, to enable "double counting" of reserve types. It is a definition not of reserve "allocated" to contingency/restoration, but of reserve that is "usable" for contingency/restoration and which includes the two other defined types of reserve, Frequency Responsive and Regulating. This distinction, between "usable" and "allocated" remains notoriously unclear in this definition, and in apparent contradiction to the provision against double-counting of reserve in the "Guidance Document" currently in preparation. To make the distinction clear, and that occasional "double counting" of reserve types is specifically being allowed by the BAL performance standards, this definition needs to be broken into two definitions. The term "Contingency Reserve" defined in the current definition should be changed to "Reserve Usable for Contingencies" which should be the term used in requirement R2. A second, clear definition of "Contingency Reserve" should be made for use in the Guidance Document, as reserve "allocated" for contingency/restoration, and the term "Contingency Reserve" should thereby be made clearly usable in that document's admonition against double counting of the three types of reserve: Frequency Responsive, Regulating, and Contingency.
Yes
No
You mean not "possible issues" but "possible issues related to EOP standards". Otherwise, see answer to question 2 about other issues.
No
As explained in my Comment to Question 2, the commonly used term "Contingency Reserve" needs to be unpacked into two terms: "Contingency Reserve" (to be used in the "Guidance Document" currently being prepared) and "Reserve Usable for Contingencies" (to be used in this standard instead of "Contingency Reserve"). The FERC Directive 693 did not identify and sort out this ambiguity and called simply for a requirement of undifferentiated "response" to a contingency, without distinguishing between the three intrinsic "types" of response, namely Frequency Response, Regulating Response, and Contingency Response, except to designate the "objective"/cause of the Response. All three types of response can meet that objective. The FERC Directive then sought to expand the definition of Contingency Reserve to include demand-side resources, and to set the requirement of a quantity of "Contingency Reserve", without specifying "Contingency Reserve" as any particular reserve type. So, yes, R2 does address the FERC Directive, but the FERC Directive is itself inadequate for failing to make the all-important distinction between type of reserve, and usability of different reserve types to meet a single reliability objective which would be some generalized "Responding" to a "Contingency" without specifying the "type" of response which distinguishes reserve types. Rather than simply "address" a technically uninformed FERC Directive, NERC should in its superior reliability wisdom/competence seek to improve upon the FERC Directive and establish the precedent that FERC takes technical direction from NERC, not the other way around and without opposing or contradicting FERC.
Yes
Yes
Yes
No
The definition of "Best ACE" is unclear as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. The purpose of this definition of "Best ACE" is to prevent R1's sanctioning a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. By this definition of "Best ACE" a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording that I show in my Comment to Question 10.

would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period.”
The wording of the recovery target ACE in Requirement 1 needs to be replaced as follows: "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur WITHIN THE CONTINGENCY EVENT RECOVERY PERIOD [caps mine]" should be replaced by "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur AT THE MOMENT OF RECOVERY (OR NEAREST-RECOVERY), or beforehand [caps mine]". Otherwise, by containing the word "all" in the selected wording, R1 sanctions a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. Furthermore, the current R1 definition contradicts the definition of "Best ACE" contained in the Background Document that was intended to preempt such BA behavior by defining "Best ACE" as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period.”
Group
Iberdrola USA
John Allen
Rochester Gas & Electric
Agree
NPCC
Individual
Steven Wallace
Seminole Electric Cooperative, Inc.
Yes
Yes
No
As written, it arbitrarily precludes the calculation of an RSG ACE for an entire RSG based upon the aggregate frequency bias, and the RSG participants' net interchange with non-participants. The Florida Reserve Sharing Group monitors participants' individual ACE, but calculates an RSG ACE based on the aggregate frequency biases and net interchange with non-participants.
Yes
No
This standard ahs been and should continue to be results based. R2 imposes a tracking and evidentiary requirement which is unreasonable and is not warranted by past performance and results. If the logical next step to be standards proscribing the measurement, qualification, etc. for contingency reserves?
No

Agree with the the VRF for R1, but not R2 for the reasoons described in response to Question 6.
No
Same response as Question 6.
No
Yes
Provide flexibility for an RSG ACE to be calculated based on aggregate participants frequency bias and RSG interchange with non-participants.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Services
No
The PPL NERC Registered Affiliates suggest striking the language “due to forced outage of transmission equipment.” A responsible entity can cut a tag for reasons other than a forced outage of transmission equipment (equipment OLs, contingency/stability/voltage criteria, etc.) – the sink BA experiencing the loss of the import may not know the reason and thus not know if the loss meets the definition of a Balancing Contingency Event. The SDT replied to this comment during the Formal Comment Period, but missed the point. The curtailment would be communicated, however, the reason, “due to …” would not necessarily.
No
The PPL NERC Registered Affiliates believe the proposed modifications actually introduce ambiguity and error. Attempting to provide examples (such as…) in definitions is ill-advised as this adds ambiguity to the definition as the list may be considered all inclusive by some and not by others. The final sentence should be struck. As defined by NERC, Demand Side Management includes “all activities” used to “influence” energy usage, which includes programs such as time of day rates, light bulb replacement, and other efficiency programs which do not provide controllable capacity. It appears the SDT may have intended to include the NERC defined term Direct Control Load Management as an example, however, examples need not be included in definitions.
No
The PPL NERC Registered Affiliates believe the definition should include only those BAs participating in the specific event, not simply all BAs that are members of the RSG. Suggest revising the definition as follows: -- Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that are participating in the Balancing Contingency Event. --
No
The PPL NERC Registered Affiliates do not agree with the proposed modifications to the NERC defined term Contingency Reserve as explained in our comment 2.
No
PPL NERC Registered Affiliates do not agree that the development of additional requirements is necessary to meet the FERC directive for a continent wide policy. Additional comments on this topic provided under question 10.
No

It is not clear to the PPL NERC Registered Affiliates why the SDT chose to use the loss of load (negative loss values included in the CERTS statistics) when determining the reportable threshold for BAL-002. The document fails to include the criteria that were used to define a “significant impact on frequency”.
The PPL NERC Registered Affiliates offer the following comments: With respect to the proposed definitions, it is not clear why the SDT modified each of the proposed definitions but is only requesting input on a subset of the defined terms during this comment period. With respect to requirement 1, it is suggested that the phrase “Except when an Energy Emergency Alert Level 2 or Level 3 is in effect,” be deleted for the following reasons: 1) An EEA in effect for any BA or RSG other than the responsible entity experiencing the contingency should not give the responsible entity an exemption from R1. For example, an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent responsible entity anywhere in the eastern interconnection. The language makes the assumption that both the EEA and contingency are affecting a single, specific responsible entity – if this is what the SDT intended, the language as currently written is too generic. 2) The Applicability section clearly states that the standard does not apply to a responsible entity under an EEA. If the SDT intends to include the exemption in the requirement language, it is suggest R1 is revised as follows: “Except when an Energy Emergency Alert Level 2 or Level 3 has been requested by the Responsible Entity, the Responsible Entity experiencing a Reportable …” . Also, we suggest it would be more appropriate for the Responsible Entity to restore ACE to within the BAAL limits rather than the “hard” zero or pre-contingent ACE value within the 15 minute recovery period. Once a responsible entity has restored ACE within the BAAL limits it is no longer burdening the interconnection – this would be a sufficient recovery. We suggest that a successful response by the responsible entity would return ACE to the lesser of 0 or its real time BAAL limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly – ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL limit (if its Pre-Reportable Contingency Event ACE was negative). With respect to R2, it is not clear if responsible entity experiencing a non-reportable Balancing Contingency Event (i.e. a loss less than 500MW) is expected to maintain Contingency Reserves at least equal to its MSSC. As currently written, it appears that R2 could require a Responsible Entity to always carry Contingency Reserves equal or greater than its MSSC plus 500MW (or its reportable threshold) so that Contingency Reserves will always exceed MSSC. With respect to measurement M2, it is not clear if Contingency Reserves may fall below MSSC for the first 105 minutes (Contingency Event Recovery Period plus Contingency Reserve Restoration Period) following any deployment of Contingency Reserves. If so, this may resolve the current expectation as written in R2. However, measures are not requirements and therefore, compliance is not judged through any potential flexibility provided in M2 or the VSLs. Requirement 2 (along with the currently effective version 1 of BAL-002) uses a capitalized term “Disturbance Recovery Period” that is not in the NERC Glossary of Terms. The SDT may have intended to use the term Contingency Event Recovery Period in lieu of Disturbance Recovery Period in requirement 2.
Group
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
BAL-002, R1 states that the Responsible Entity shall demonstrate that it returned its ACE to zero (less some modifiers); in other words, the standard requires ACE to be returned to an absolute number, without a tolerance. I believe this is not the intent of the SDT, that they probably meant zero or

positive, or something like that; but, reading the requirement literally, I believe it would be difficult to prove compliance using integrated values for ACE that will likely not equal zero.
Group
MISO Standards Collaborators
Marie Knox
MISO
No
No
The presently approved NERC definition for contingency seems adequate for this standard.
No
This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
No
It needs a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
No
R2 has nothing to do with a Continent Wide Contingency Reserve Policy and there is nothing in the drafting team's SAR that calls for the implementation of a commodity standard. This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR nor in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. A fundamental flaw in R2 is that drafting team has implemented a commodity expectation that the BA must have contingency reserves above MSSC at all times and yet has provided no clear definition on how this is measured (does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What type of proof of deliverability is required? Some of the background information implies that frequency responsive resources must be removed from the Contingency Reserve calculation. How much? All headroom? Enough to provide the IFRO? This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the ultimate demonstration of adequacy. We believe the way a way to achieve the Commissions directive for a continent wide "contingency reserve" policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The document the drafting team is working on is a good start. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through

the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
No
We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Yes
No
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
There first needs to be agreement on the requirements before there is concurrence with the background document.
Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today’s DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team’s SAR and the Order No. 693 directives. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. A Contingency Reserve Policy Guideline document in conjunction with the recommendations below should be sufficient to meet the drafting team SARs and the directives: • Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). • Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. • Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. Also BAL-001’s RBC is a more effective way to meet the FERC directive for loss of load events. • The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA’s performance approaches non-compliance. • The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.
Group
Tampa Electric Company
Ronald L Donahey
Tampa Electric Company
Agree
Duke Energy
Individual
Christopher Wood

Platte River Power Authority
Agree
Public Service Company of Colorado (Xcel Energy)
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
Yes
No
The definition should include only the BAs asked to participate in the reserve recovery event.
Yes
No
The proposed requirement would have significant negative consequences as Reserves are an inventory intended to be used when there is a reliability need. A BA could be encouraged to never deploy their CRs except for during a DCS-reportable event. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the time would start ticking on the ‘available hours’ clock. Additionally, BAs that don’t withhold CRs for non-DCS events might feel the need to increase the amount of contingencies they carry in order to always have more reserves than their MSSC which in turn, would increase customer costs without a demonstrated need. We suggest that not all BAs have the same needs for the various types of operating reserves and that performance is the demonstration of adequacy. We suggest the SDT work with the NERC OC to create a policy document that outlines the factors the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves and provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standard’s process, we suggest that NERC add these four types of reserves to ‘Attachment 1-TOP-005 Electric System Reliability data” with the noted expectation that RCs collect this information in real time for use in the EEA process. While we agree with the principle of a BA maintaining Contingency Reserves to respond to its MSSC, the proposed R2 puts the BA at risk if CR reserves fall below its MSSC for any single sampling period. For example, BAs with a 2 second sampling interval would be at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the proposed Measures and VSLs, we suggest that specific language be included in R2 and not just in the Measure (SERC OC). A reference to the integrated clock hour should be included in R2 as in the Measure.
Yes
It is difficult to agree with the VRFs while disagreeing with the standard as proposed.
Yes
Yes
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
The Background Document states on page 4 that “FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation.” We disagree with this interpretation of the Commission’s directive. In Order 693 (P355) the Commission declined to define a ‘significant deviation as a frequency deviation of 20 mHz’, but

instead directed the ERO ‘to define a significant deviation and a reportable event’. The Commission directed that ‘loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,’ must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, no matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the background document relating to the methodology for development of the reporting thresholds.

There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn’t in the drafting team’s SAR or in a directive. Events greater than MSSC should be reported but not evaluated for compliance. While it’s fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT’s goal of drafting a continent-wide standard but disagree with the SDT’s approach of ‘one size fits all’ in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT’s have acknowledged that a ‘one size fits all’ approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO’s. The State of Reliability Report prepared by the NERC identifies “the triggers for significant frequency events” that are specific to each Interconnection. We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE – this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The “Applicability” section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the “hard” criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection – wouldn’t this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero)

and similarly – ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high – why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply.
Individual
Spencer Tacke
Modesto Irrigation District
No
It is in conflict with the very definiton of a balancing authority.
Yes
No
A technical justification for the "16 second interval" for ACE and the "105 minutes" value for Contingency Reserve demonstration needs to be added.
Individual
Thomas Washburn
FMPP
Agree
FMPA
Group
ERCOT
H. Steven Myers
ERCOT ISO
Yes
Yes
ERCOT ISO suggests that the SDT consider the following changes so that the definition of the Contingency Reserve clearly accommodates resources eligible under the respective BA rules to provide Contingency Reserve for that BA: "The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by 'resources eligible under the respective BA rules, including, but not limited to,' resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation."
Yes
Yes
Yes

Yes
Yes
Yes
ERCOT ISO supports the intention of the standard BAL-002-2 R1 to restore ACE back to pre-disturbance ACE but not necessarily to zero or the pre-disturbance ACE. The ACE recovery goal should be pre-disturbance levels. Therefore, ERCOT suggests the SDT establish a (epsilon1*Frequency Bias*10) band around the pre-disturbance ACE or zero ACE, and, if during recovery ACE is recovered within this range, entities would be compliant. This structure of establishing a goal, but providing for a compliance "floor" based upon the proposed range, will achieve the desired reliability benefits while also providing a reasonable degree of flexibility for circumstances where recovery to the exact pre-disturbance level is difficult to achieve, and unnecessary to ensure reliability. ERCOT ISO also suggests that the 500 MW threshold be removed from the definition of Reportable Balancing Contingency Event. This requirement would impose an undue burden. There is no reliability reason to require mandatory reporting for these smaller events. It will merely create an administrative obligation with no corresponding reliability benefits. For instance, currently ERCOT ISO would typically need to report less than five events annually, but this new standard would increase this reporting burden to over 50 each year (based upon 2012 disturbances), without any corresponding reliability benefits. Accordingly, this obligation should be removed. If the SDT elects not to remove the 500 MW threshold generally, ERCOT ISO suggests that the threshold be removed for single-BA Interconnections. The threshold for single-BA Interconnections should be established as 80 percent of the MSSC. ERCOT ISO is voting "yes", but has reservations as described above and requests that the SDT revise the standard accordingly.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
The definition is not explicitly clear about normal operating actions such as special protection system (SPS) actions. Certain transmission events may lead to generation rejection so the system stays stable after the fault. If we interpret the proposed definition and use the same terminology, these actions are planned, the change on the ACE is not unexpected, and they could be considered as a secondary event. The generation does not become unavailable following the trip. Consequently, these events would not classify as Balancing Contingency Events. During the 04/02/2013 webinar, the Standard Drafting Team provided an answer in this direction. We then understand that a CR Form 1 should not be filled for these types of events. However, we believe that the Balancing Contingency Event definition should be clarified to minimize the risk of misinterpretation if this is the SDT's intent. We suggest adding a bullet in the definition stating that normal operating characteristics of a unit or a system such as SPS actions do not constitute a sudden or unanticipated loss and are not subject to this definition. Additionally, some single contingencies may lead to generation loss as well as load loss after the breaker operations. For example, if 1200 MW of generation is loss and 1000 MW of DC converters at the same time, the net loss for the grid is 200 MW, which would be under the Reportable Balancing Contingency Event threshold. For this reason, the Balancing Contingency Event definition should include the notion of net loss for the grid.
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Group
ACES Standards Collaborators
Jason Marshall
ACES
No
(1) We appreciate the changes that have been made to the Balancing Contingency Event definition. It is much less complicated and more clear as a result. However, there still has not been a justification provided for the need of the definition. There is a statement in the background document that the previous version of the standard was “broad and could be interpreted in various manners”. A specific explanation how the definition addresses the ambiguity should be provided. (2) We disagree with including subsection (c) in the Balancing Contingency Event definition. Subsection (c) includes sudden “loss of a known load used as a resource”. Loss of a load will result in positive ACE regardless of whether it is being used a resource or not. As a result, BAL-002-2 R1 will be duplicative with BAL-013-1 R1. Both will compel recovery of ACE from the loss of a load. Think of it this way. If a 1000 MW load is used as a resource to respond to a BA’s ACE that is at -100 MW, there would be 900 MW of load remaining once the load is reduced. If that load is then lost, ACE goes to 900 MW. Shouldn’t this be covered by the proposed BAL-013-1?
No
Please strike the last sentence of the definition. It is an explanation of what may constitute contingency reserve and is not actually part of the definition. It should be included in the background document. We understand the reason for the inclusion may be in response to a directive to further the Commission’s policy on expanding the use of DSM. However, the use of DSM has expanded significantly since the directives were issued and could be said to have been “overcome” by events. It is well understood within this industry that DSM may be used as a resource. The drafting team could include an explanation in the application guidelines or the background document that would explain that DSM could be used among other resources.
No
We believe the definition as proposed is already a common understanding and is not needed. We simply do not see how it adds value. Further, having multiple definitions for ACE creates confusion and is simply not needed.
No
(1) We do believe that it is helpful to clarify that a BA does not have to comply with recovering ACE and contingency reserves when it is in an EEA 2 or 3. It certainly would not make sense to go to the extreme of shedding firm load to recover ACE or contingency reserves if a BA was simply out of balance with no transmission security issues, system frequency issues or stability issues. There are standards requirements such as operating within IROLs/SOLs that would deal with these other reliability issues and provide the indication if load needed to be shed to address the deficient BA. A more efficient way to address this issue may be to apply the restriction in the applicability section. (2) It would be helpful if the drafting team explained what the conflicts with the EOP standards are. Besides the one identified above, are there others? The background document states that there are conflicts but does not explain them. It is difficult to judge if the issue was addressed without an adequate explanation.
No

(1) We are concerned that this requirement will have unintended consequences. As written, a BA will be forced to only deploy contingency reserve for responding to resource contingencies. Consequently, the BA will have to carry more operating reserves which increases their operating costs tremendously without commensurate reliability benefit. Furthermore, there is no data indicating that operating reserves carried by BAs today are insufficient. (2) While contingency reserve is just one type of operating reserve and is intended for use to respond to contingent events, a BA should not be restricted to deploying it only for contingent events. There may be other reasons for a BA to have a large negative ACE (i.e. units don't ramp as expected) and the BA should be free to call upon its contingency reserve to recover ACE in such a situation. Since the FERC directive that is driving this requirement is to establish a continent wide policy on contingency reserve, a better solution would be for NERC to write an operating policy describing appropriate uses of various types of contingency reserves. A guideline document would provide better details for an operating policy than a requirement.
No
We agree with the VRF for requirement R1 but do not agree with requirement R2 as written. Thus, we do not agree with the VRF for Requirement R2.
Yes
No
We disagree with the VSLs for both requirements. The VSLs for requirement R1 raise the bar significantly for compliance without a technical justification. Today, DCS compliance is determined by a quarterly average of response to events. Thus, failure to recover ACE for two events within the same quarter would be a singular violation. As proposed, the new VSLs would treat each event as a separate violation. Without significant justification, we cannot agree with this change to the VSLs. Because we do not agree with Requirement R2, we do not agree with the corresponding VSLs.
No
(1) The background document needs to explain the conflict between BAL-002 and EOP-002 in detail rather than just stating that a conflict exists. (2) There is a statement on page 5 just before the Rationale by Requirement section that there are other definitions that have been added or modified. An explanation of what these are would be helpful. (3) The formulas starting on page 8 are overly complicated in an attempt to address the few situations where there are additional generator contingencies that occur shortly before or during the ACE recovery window. We suggest starting with simple formulas that consider that predominant situation where only one generator contingency occurs. Then build the more complicated formulas on that. It will be easier to explain. We also suggest using pictures to explain the formulas. For example, a graph showing the loss of a unit before and after the current contingency would help explain the formulas. The graph should include labels such as what ACE_BEST, ACE_PRE, and MEAS_CR_RESP are.
(1) We cannot support a 500 MW threshold for a Reportable Balancing Contingency Event. The number is arbitrary without any technical justification. The background document explains how the drafting team reviewed CERTS data to arrive at the conclusion that a 100 MW threshold would cover all frequency events. Correctly, the drafting team determined that this was simply an unrealistic threshold and would not provide any additional reliability value. The background document then explains that the drafting team decided "to capture the majority of events having significant impact on frequency" by setting the threshold to 80% of the MSSC or 500 MW. It did not explain which value would do this or why it was important "to capture the majority of events". Furthermore, there is no explanation why 500 MW is necessary when today 80% of MSSC is used. Has the use of 80% of MSSC resulted in an unreliable system? Thus, we can only conclude the value is arbitrary. Please remove the 500 MW value. (2) Additional justification is necessary to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, it is not consistent with BAL-005-0.2b which requires ACE calculation on at least a six second basis. A BA using a six-second sample rate could be viewed as being out of compliance if they used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any glitches in the data. What does an entity do if a scan was skipped or there was a data spike? More samples would make it

less likely for this to be an issue. (3) The purpose needs to be modified. Please strike “balances resources and demand and”. The purpose of the standard is to recover ACE following a Reportable Balancing Contingency Event. The portion that needs to be struck is addressed by BAL-001. (4) The drafting team has an opportunity to assist NERC in moving the Reliability Assurance Initiative along and showing some of the first fruits of the initiative. One of the key white papers written for the initiative focuses on the reducing the data requirements and retention periods necessary for the compliance and enforcement process. NERC compliance has a stated goal of reducing the data retention burden on registered entities. The data retention required for the current versions of this standard exceed what is necessary and this draft version perpetuates the problem. All BAs currently must submit monthly data to their regional entities for this standard which clearly shows whether they are compliant or not. Then they are still required to retain three years worth of data. Since the regional entities already have the data and know whether they are compliant or not, what reliability value does three years of data provide? None. The new version will only perpetuate this issue. In response to our previous comments, the drafting team indicated that the monthly reporting is not required by the standard and is up to the region. While this is true, it is highly unlikely that the regional entities will change this monthly reporting burden given that the standard is conceptually the same as the existing standard. Furthermore, the drafting team and NERC staff can review the issue with regional entity compliance personnel to confirm their plans for monthly reporting. If they do plan to continue with the monthly reporting, then no more than six months of data is necessary and we request that the standard should be changed. It will demonstrate a good faith effort on the part of NERC to move the RAI forward. (5) The data retention section is inconsistent with the 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. Since a BA is on a three-year audit cycle, the period from the previous audit will be about 3 years. It could be a little more or a little less. However, the data retention section of “the current year, plus three previous calendar years” (which could be up to four years) actually could exceed this three year audit cycle period. Consider if a BA completed their last audit on November 15, 2010. Their audit cycle would require another audit in 2013. Let’s assume this is scheduled for December 15, 2013. This means the audit period is 3 years and 1 month. It also means per the Rules of Procedure that NERC cannot review any period prior to November 15, 2010 for compliance unless there is an outstanding investigation. Per the data retention section, on December 15, 2013, the date of the audit, the BA would have to retain data for all of 2013 as well as all of the data for 2010, 2011 and 2012. By the Rules of Procedure, the auditors could not review any data prior to November 15, 2010. Thus, the registered entity would be compelled to retain for 11.5 months for which NERC is not allowed to review. How does this benefit reliability? The data retention period should be changed to retain data since the last audit. Changing the data retention period to be no longer than since the last audit would show a good faith effort in moving the RAI along. (6) The VSLs for Requirement R2 need to be justified. There is no explanation provided for the values chosen for the various thresholds. For example, the Lower VSL covers contingency deficiency for a period of 5 to 15 hours. Why shouldn’t this go to 20, 30, 40 or any other number of hours? Without a justification, we can only assume the numbers were selected arbitrarily. We are also confused by the Lower VSL since it starts at 5 hours. Does this mean that a BA can be deficient of contingency reserves up to 5 hours without a violation occurring? (7) There is no explanation for why Reportable Disturbance is not a satisfactory definition as used in the existing standard and why it is replaced with Reportable Balancing Contingency Event. Furthermore, it is not proposed to be retired. If the term will no longer be used, it should be retired. (8) Thank you for the opportunity to comment.
Individual
John Bee on Behalf or Exelon and its Affiliates
Exelon

While we appreciate the work done since previous versions of the project, and recognize the clarity gained by eliminating reference to Balancing Contingency Events with a future impact to ACE, we feel that additional confusion has been inserted by the sub-points of R1. Given that the recovery requirement is a relatively short time-frame, the ability to quickly determine the recovery obligation is critical to the ability to ensure compliance. We appreciate that the drafting team is attempting to accommodate the notion that a prior Balancing Contingency Event might impact any future events, but the methodology given for determining the recovery threshold is overly complex, and represents a significant barrier to a system operator's ability to interpret the requirement in Real Time and respond appropriately.
Individual
William O. Thompson
NIPSCO
Agree
MISO
Group
Tennessee Valley Authority
Dennis Chastain
Tennessee Valley Authority
Agree
SERC OC Standards Review Group
Individual
David Gordon
Massachusetts Municipal Wholesale Electric Company
Agree
Northeast Power Coordinating Council, Inc (NPCC) ISO New England, Inc.
Group
Oklahoma Gas & Electric
Terri Pyle
Oklahoma Gas & Electric
No
The definition of Reportable Balancing Contingency Event includes “the lesser of 80 percent of the MSSC or 500 MW”. We believe that the threshold of 500 MW is too low. This is going to result in an excessive number of “reportable” events that do not have an impact on reliability. The retrieval and analysis of data will be burdensome and provide little value.
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Remove the 500 MW threshold in the definition of Reportable Balancing Contingency Event
Group
IRC-SRC
Terry Bilke
MISO
No
We don't see the need for the added definition.
No
The presently approved NERC definition for contingency reserve seems adequate for this standard.
No
This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
No
All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
No
We believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe the way a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
No
We believe the requirement itself is inappropriate, so any VRF is unnecessary.

Yes
No
Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
No
There first needs to be agreement on the requirements before there is concurrence with the background document.
Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL is crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendation are: • Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). • Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. • Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. • The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. • The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Program
No
BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden loss of known load used as a resource that causes an unexpected change to responsible entity's ACE. BPA also recommends leaving in the failure to start language that has been removed.
Yes
Yes
Yes

Yes
Yes
Yes
No
BPA recommends changing the VSLs for R2 to: Lower VSL more than 2 but less than or equal to 5 hours; Moderate VSL more than 5 but less than or equal to 10 hours; High VSL more than 10 but less than or equal to 15 hours; Severe VSL More than 15 hours.
Yes
BPA is in support of this standard.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Yes
The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. Therefore, Xcel Energy is voting against the proposed standard. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by Xcel Energy, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. Xcel Energy is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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	1	2	3	4	5	6	7	8	9	10
4.	Group	Robert Rhodes	SPP Standards Review Group		X								
5.	Group	Stuart Goza	SERC OC Standards Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
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 4 (Robert Rhodes, SPP Standards Review Group):

	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 5 (Stuart Goza, SERC OC Standards Review Group):

	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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

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	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

	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	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	Oklahoma Gas & Electric	SPP	1
2.	Donald Hargrove	Oklahoma Gas & Electric	SPP	3
3.	Leo Staples	Oklahoma Gas & Electric	SPP	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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				

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.

Organization	Yes or No	Question 2 Comment
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**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3">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.</td></tr>
<tr><td>City of Tallahassee</td><td>No</td><td>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</td></tr>
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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

Consideration of Comments

Project 2010-14.1 (BAL-002-2)
Phase 1 of Balancing Authority Reliability-based Controls: Reserves

The Balancing Authority Reliability-based Controls: Reserves Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-001-2 Real Power Balancing Control Performance. These standards were posted for a 45-day public comment period from March 12, 2013 through April 25, 3013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 55 sets of comments, including comments from approximately 179 different people from approximately 108 companies representing all 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.

- Modified the definition for a Balancing Contingency Event to provide additional clarity.
- Modified the definition for a Reportable Balancing Contingency Event to use Interconnection specific thresholds instead of a continent wide threshold.
- Modified Requirements R1 and R2 to provide additional clarity.
- Modified the VSL for Requirement R1 to provide additional clarity.
- Modified the Background Document to provide additional clarity.

There were a couple of minority issues that the team was unable to resolve, including the following:

- A couple of stakeholders felt that the proposed BAL-001-1 draft standard was sufficient to cover a DCS event and that BAL-002 could be deleted. The drafting team appreciated their comments and recognized the potential overlap of BAL-001 and BAL-002. However, the drafting team did not believe the time was right for combining the two standards. The drafting team believes that in order to advance this process of combing the two standards these two proposed standards need to move forward. The drafting team supports moving this issue forward and is committed to submit a SAR supporting this concept for future development.
- Some stakeholders questioned why the drafting team was not using the term Reportable Disturbance. The drafting team explained that the term Disturbance as defined by the NERC Glossary of terms is extremely broad and not specific. The Term Balancing Contingency Event was defined to allow the drafting team to be more specific as to what should be considered for the purposes of this standard.
- A couple of stakeholders wanted the drafting team to use BAAL as the measure for performance in this standard. The drafting team explained that they considered using the approach of BAAL as the measure for performance in this standard but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

- A few stakeholders felt that there should only be a statement in the applicability section stating that this standard did not apply to a BA when it was in an EEA Level 2 or 3. The drafting team explained that they included it in both the applicability section and in the requirement to assure no misinterpretation by the auditors.

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 Coodinating 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 Electricity 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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
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

2.	Group	Russel Mountjoy-Secretary	MRO NERC Standards Review Forum	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel	MRO	1, 3, 5, 6
2.	Dan Inman	MPC	MRO	1, 3, 5, 6
3.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
4.	Jodi Jensen	WAPA	MRO	1, 6
5.	Joseph Depoorter	MGE	MRO	3, 4, 5, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Lee Kittleson	OTP	MRO	1, 3, 5
8.	Marie Knox	MISO	MRO	2
9.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
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	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
2.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
3.	Jerry McVey	Sunflower Electric Power Corporation	SPP	1
4.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
5.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
6.	Allan George	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Stuart Goza	SERC OC Standards Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Harrison	AECI	SERC	3, 5, 6, 1
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.	Terry Bilke	MISO	SERC	2
9.	Brad Gordon	PJM	SERC	2
10.	Jim Case	Entergy	SERC	1, 3, 6
11.	Wayne Van Liere	JGE-KU	SERC	1, 3, 5, 6
12.	Phil Whitmer	Georiga Power Company	SERC	3
13.	Bill Thigpen	PowerSouth	SERC	1, 5
14.	Tim Hattaway	Power South	SERC	1, 5
15.	Troy Blalock	SCE&G	SERC	1, 3, 5, 6
16.	Glenn Stephens	SCPSA	SERC	1, 3, 5, 6
17.	Sammy Roberts	Progress Energy	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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21. Cindy Martin		Southern	SERC 1, 5										
22. Jimmy Cummings		Southern	SERC 1, 5										
23. M. D. Tucker		Southern	SERC 1, 5										
24. Randy Hubbert		Southern	SERC 1, 5										
25. Kelly Casteel		TVA	SERC 1, 3, 5, 6										
5.	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. 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
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	Kent Kujala	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Al Eizans		RFC	3, 4, 5
2. Dan Herring		RFC	3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	John Allen	Iberdrola USA	X									

Additional Member	Additional Organization	Region	Segment Selection
1. Joseph Turano	Central Maine Power	NPCC	1
2. Raymond Kinney	New York State Electric & Gas	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				
11.	Group	Marie Knox	MISO Standards Collaborators		X								
12.	Group	Ronald L Donahey	Tampa Electric Company	X		X		X	X				
13.	Group	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				
14.	Group	H. Steven Myers	ERCOT		X								

(Continued additional members of previous group:)

Additional Member	Additional Organization	Region	Segment Selection
3.		WECC	5
4. Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.		NPCC	6
6.		SERC	6
7.		SPP	6
8.		RFC	6
9.		WECC	6

Group 10 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6. Randy Hahn	Ocala Utility Services	FRCC	3

Group 11 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1. Joe O'Brien	NIPSCO	RFC	6

Group 12 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1. Sara E Young			1
2. Benjamin Smith III			6
3. James Rocha			5

Group 13: No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

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
15.	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
16.	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
17.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Terri Pyle	Oklahoma Gas & Electric	SPP	1
2. Donald Hargrove	Oklahoma Gas & Electric	SPP	3
3. Leo Staples	Oklahoma Gas & Electric	SPP	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	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	NEISO	NPCC	2
4. Greg Campoli	NYISO	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Charles Yeung		SPP	SPP 2										
6. Ali Miremadi		CAISO	WECC										
19.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bart McManus		WECC	1
2. Dave Kirsch		WECC	1
3. Ayodele Idowu		WECC	1
4. Don Watkins		WECC	1
5. Pam VanCalcar		WECC	5
6. Fran Halpin		WECC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
22.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
23.	Individual	Stephanie Monzon	PJM Interconnection, LLC		X								
24.	Individual	Ken Gardner	Alberta Electric System Operator		X								
25.	Individual	Tom Siegrist	EnerVision, Inc.							X			
26.	Individual	John Tolo	Tucson Electric Power	X									
27.	Individual	Rich Hydzik	Avista	X		X		X					
28.	Individual	Nazra Gladu	Manitoba Hydro			X		X	X				
29.	Individual	Rich Salgo	NV Energy	X		X		X					
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
32.	Individual	Jim Cyrulewski	JDRJC Associates LLC	X									
33.	Individual	Greg Travis	Idaho Power Company	X									
34.	Individual	Michael Falvo	Independent Electricity System Operator		X								
35.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
36.	Individual	Kenneth A Goldsmith	Alliant Energy				X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
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	Keith Morisette	Tacoma Power	X		X	X	X	X				
43.	Individual	Don Jones	Texas Reliability Entity										X
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	Steven Wallace	Seminole Electric Cooperative, Inc.			X	X	X	X				
48.	Individual	Christopher Wood	Platte River Power Authority	X		X		X	X				
49.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
50.	Individual	Thomas Washburn	FMPP						X				
51.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
52.	Individual	John Bee on Behalf or Exelon and its Affiliates	Exelon	X		X		X					
53.	Individual	William O. Thompson	NIPSCO					X					
54.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					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:

DTE Electric	Agree	MISO
Iberdrola USA	Agree	NPCC
Tampa Electric Company	Agree	Duke Energy
Tennessee Valley Authority	Agree	SERC OC Standards Review Group
JDRJC Associates LLC	Agree	Midwest ISO
Alliant Energy	Agree	MRO NSRF
City of Austin dba Austin Energy	Agree	ERCOT
Public Service Enterprise Group	Agree	PJM Interconection
Entergy Services, Inc. (Transmission)	Agree	SERC OC Standards Review Group
Platte River Power Authority	Agree	Public Service Company of Colorado (Xcel Energy)
FMPP	Agree	FMPA

NIPSCO	Agree	MISO
Massachusetts Municipal Wholesale Electric Company	Agree	Northeast Power Coordinating Council, Inc (NPCC)ISO New England, Inc.

1. **The BARC SDT has modified the definition for Balancing Contingency Event based on comments received from the industry. Do you agree that the modifications provide addition clarity? If not, please explain in the comment area below.**

Summary Consideration: Some commenters were confused as to what was meant by the term "loss of a known load". The SDT explained that they had removed this term and added clarifying language.

A couple of commenter felt that the definition was not complete since it did not specify a unit's failure to start. The SDT stated that an earlier version of the definition did contain language recognizing a unit's failure to start. The SDT removed this due to overwhelming objection from the industry for including this term.

One commenter suggested that the SDT incorporate the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. The SDT explained that the use of resource loss for determining an event size and ACE in determining recovery from an event has long been used by the industry and is in both the definition of a Disturbance and Reportable Event. The drafting team chose not to alter this practice. Additionally this compliments all the subsections of the definition, such that there is not a Balancing Contingency Event without a change in ACE.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	No	We would suggest incorporating the concept of an unexpected event with the loss itself rather than tying it to the change in ACE. For example in Subsection A, we would propose: 'Sudden, unexpected loss of generation...' Similar changes need to be made to Subsections B and C. Also, there is a timing element associated with Subsection B which could cause conflict with the wording in B. Requiring a sudden loss of import by the loss of a transmission element, implies that the loss of import would be sudden. It may or may not be. It depends on when the loss is reflected in schedules. Additionally, an entity may not know that the loss is due to a loss of transmission. We would suggest: 'Sudden, unexpected loss of an import

Organization	Yes or No	Question 1 Comment
		that causes a change to the responsible entity's ACE.' In Subsection C we suggest: 'Sudden unexpected loss of a known load...'The term 'responsible entity' is not capitalized in the definition but is in the standard. Should it be in the definition?
Response: Thank-you for your comments. The use of resource loss for determining an event size and ACE in determining recovery from an event has long been used by the industry and is in both the definition of a Disturbance and Reportable Event. The drafting team chose not to alter this practice. Additionally this compliments all the subsections of the definition, such that there is not a Balancing Contingency Event without a change in ACE. With regards to your comment concerning Section B the drafting team has made a modification to add clarity. The term "responsible entity" is not in the NERC Glossary and should not be capitalized.		
seattle city light	No	Seattle City Light considers the definition of Balancing Contingency Event proposed in this draft of BAL-002-2 to be incomplete in that it does not recognize the failure of a unit to start as an "event." Seattle recommends revising the definition to read: "A.a.i. Unit Tripping or failure to start at the scheduled time."
Response: Thank you for your comment. Based on the initial posting, the SDT removed "failure to start" from the definition due to the overwhelming objection from the industry on including this within the definition.		
Duke Energy	No	o The definition is too broad. Using the phrase "or any series of such otherwise single events" leaves much open to interpretation. In many cases it will not be clear when the 15-minute clock has been triggered. o Regarding Subsection "C.", it is also not clear what is meant by the "sudden loss of a known load used as a resource". Is the team referring to an interruptible load resource, fully loaded and counted on for provision of contingency reserve? If so, would the sudden loss of the resource mean that the load is inadvertently interrupted causing high ACE? We're not aware of a proven reliability risk that warrants a 15-minute recovery period from a high ACE. Or, is the team referring to an interruptible load resource

Organization	Yes or No	Question 1 Comment
		already implemented (curtailed) for a first contingency, and then somehow losing the curtailment capability where the resource fully loads again causing low ACE (second contingency)? If so, has any such event ever been documented to warrant placing a statement subject to interpretation in the Standard? o Duke Energy suggests striking Subsection "C.", as loss of any load is covered under the BAAL in BAL-001-2. o Based upon the above, Duke Energy suggests revising the definition to - "Balancing Contingency Event: Any single event described in Subsection (A) or (B) below, or any combination of those events occurring within less than one minute." Duke Energy suggests revising Subsection "A.b" to read "And, that causes an unexpected negative change to the responsible entity's ACE", and suggests revising Subsection "B" to state "Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected negative change to the responsible entity's ACE." Both changes are suggested to clarify that this standard is applicable to the loss of resource causing an unexpected drop in ACE. To the extent that Subsection "C" is retained, Duke Energy suggests a similar revision to insert the word "negative".
Response: Thank-you for your comments and the SDT provides the following responses: 1. **The SDT discussed this topic at length and it is not whether the loss is a single event or a series of single events, the triggering factor is the total loss within the rolling one minute time frame.** 2. **The SDT has modified Section C to address concerns expressed by the industry. The term "known load" is no longer used in the definition.** 3. **The definition has been revised after consideration of Duke Energy's comments.**		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates suggest striking the language "due to forced outage of transmission equipment." A responsible entity can cut a

Organization	Yes or No	Question 1 Comment
		tag for reasons other than a forced outage of transmission equipment (equipment OLs, contingency/stability/voltage criteria, etc.) - the sink BA experiencing the loss of the import may not know the reason and thus not know if the loss meets the definition of a Balancing Contingency Event. The SDT replied to this comment during the Formal Comment Period, but missed the point. The curtailment would be communicated, however, the reason, "due to ..." would not necessarily.
Response: Thank you for your comments but the SDT believes that requiring any such loss to be accompanied by "an unexpected change to the responsible entity's ACE" resolves your concerns. In addition, the SDT has modified the definition to provide further clarity.		
MISO Standards Collaborators	No	
ACES Standards Collaborators	No	(1) We appreciate the changes that have been made to the Balancing Contingency Event definition. It is much less complicated and more clear as a result. However, there still has not been a justification provided for the need of the definition. There is a statement in the background document that the previous version of the standard was "broad and could be interpreted in various manners". A specific explanation how the definition addresses the ambiguity should be provided. (2) We disagree with including subsection (c) in the Balancing Contingency Event definition. Subsection (c) includes sudden "loss of a known load used as a resource". Loss of a load will result in positive ACE regardless of whether it is being used a resource or not. As a result, BAL-002-2 R1 will be duplicative with BAL-013-1 R1. Both will compel recovery of ACE from the loss of a load. Think of it this way. If a 1000 MW load is used as a resource to respond to a BA's ACE that is at -100 MW, there would be 900 MW of load remaining once the load is reduced. If that load is then lost, ACE goes to 900 MW. Shouldn't this be covered by the proposed BAL-013-1?

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments: 1. **The SDT chose to use a more specific and granular definition rather that the current definition – Disturbance which is broad and vague and is subject to interpretation.** 2. **The SDT interprets your comments as being a loss of load event which was not the intention. Section C has been modified to clarify the intention and address concerns expressed by the industry.**		
Oklahoma Gas & Electric	No	The definition of Reportable Balancing Contingency Event includes “the lesser of 80 percent of the MSSC or 500 MW”. We believe that the threshold of 500 MW is too low. This is going to result in an excessive number of “reportable” events that do not have an impact on reliability. The retrieval and analysis of data will be burdensome and provide little value.
Response: The SDT has modified the definition to address the concerns expresses by the industry regarding the threshold. Please refer to the Background Document for further clarification on this issue.		
IRC-SRC	No	We don't see the need for the added definition.
Response: The SDT chose to use a more specific and granular definition rather that the current definition – Disturbance which is broad and vague and is subject to interpretation.		
Bonneville Power Administration	No	BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden loss of known load used as a resource that causes an unexpected change to responsible entity’s ACE. BPA also recommends leaving in the failure to start language that has been removed.
Response: Thank you for your comments. **If loss of a transmission facility results in an unexpected change to ACE it meets the definition.** **The SDT has modified Section C to address concerns expressed by the industry. The term “known load” is no longer used in the**		

Organization	Yes or No	Question 1 Comment
definition. **Based on the initial posting, the SDT removed "failure to start" from the definition due to the overwhelming objection from the industry on including this within the definition.**		
Avista	No	The changes to the definitions add clarity, but ambiguity still exists around one phrase. What constitutes an "unexpected change to the responsible entity's ACE?" Does this mean that there is no human action when the ACE change occurs? Does this mean that a human action to change a Net Interchange value in the ACE equation is "unexpected" when it is due some force majeure condition? Clarity around this issue is necessary to prevent Balancing Authorities (BA) from merely adjusting their Net Schedule Interchange value to correct ACE and passing the problem on to another BA. If transmission curtailments and unexpected adjustments to e-tags are acceptable events to deploy contingency reserve and are considered "Sudden Loss of Generation" under BAL-002-2, this needs to be explicitly stated. If transmission curtailments and unexpected adjustments to e-tags are NOT acceptable events to deploy contingency reserve and are NOT considered "Sudden Loss of Generation" under BAL-002-2, this needs to be explicitly stated. The Background Document discusses frequency deviations on Page 4 under "Balancing Contingency Event." This seems to preclude any human action to alter Net Scheduled Interchange as a "Balancing Contingency Event."
Response: Thank you for your response. The SDT considers the word "unexpected" to be clear and to be accepted by the industry. **The SDT is unsure as to the meaning of your comment concerning the Background Document and human action. Without further clarity the SDT cannot provide a response.**		
NV Energy	No	Inclusion of "Sudden loss of a known load" is at odds with the Contingency

Organization	Yes or No	Question 1 Comment
		Reserve definition, especially in light of the fact that loss of load cause ACE to increase (become more positive). In other words, why would one carry reserves to handle a decrease in load? It's illogical. What the SDT may be trying to reference is the use of interruptible load as a type or reserve. As such, load should not be in the Contingency Event definition.
Response: Thank you for your response. The SDT disagrees that it is trying to reference interruptible load as a type of reserve. The SDT has modified Section C to address concerns expressed by the industry. The term "known load" is no longer used in the definition.		
Energy Mark, Inc.	No	The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Response: Thank you for your response. The drafting team suggests that you intended to say "Reporting ACE" since "Reportable ACE" has not been proposed as a new definition. We agree with you suggestion, that the proposed definition of "Reporting ACE" should be included in both this standard and BAL-001-2 until it is approved and included in the Glossary.		
Tacoma Power	No	Tacoma Power is unfamiliar with the phrase, "... known load used as a resource ..." We believe the industry cannot interpret these words consistently. Instead, we suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation.
Response: Thank you for your response. The SDT has modified Section C to address concerns expressed by the industry. The term "known load" is no longer used in the definition.		
Hydro-Quebec TransEnergie	No	The definition is not explicitly clear about normal operating actions such as special protection system (SPS) actions. Certain transmission events may lead to generation rejection so the system stays stable after the fault. If we interpret the proposed definition and use the same terminology, these actions are planned, the change on the ACE is not unexpected, and they

Organization	Yes or No	Question 1 Comment
		could be considered as a secondary event. The generation does not become unavailable following the trip. Consequently, these events would not classify as Balancing Contingency Events. During the 04/02/2013 webinar, the Standard Drafting Team provided an answer in this direction. We then understand that a CR Form 1 should not be filled for these types of events. However, we believe that the Balancing Contingency Event definition should be clarified to minimize the risk of misinterpretation if this is the SDT's intent. We suggest adding a bullet in the definition stating that normal operating characteristics of a unit or a system such as SPS actions do not constitute a sudden or unanticipated loss and are not subject to this definition. Additionally, some single contingencies may lead to generation loss as well as load loss after the breaker operations. For example, if 1200 MW of generation is loss and 1000 MW of DC converters at the same time, the net loss for the grid is 200 MW, which would be under the Reportable Balancing Contingency Event threshold. For this reason, the Balancing Contingency Event definition should include the notion of net loss for the grid.
Response: The SDT does not agree with your comment that the definition needs to be modified to address your concern. The activation of a SPS may cause a contingency event on the system with the SPS or another system.		
MISO Standards Collaborators	No	
Texas Reliability Entity	Yes	Definition of "Balancing Contingency Event" is slightly different in Implementation Plan as compared to Standard (A.a.iii. Facility vs Facilities, B. Import vs import...). Definition of "Reportable Balancing Contingency Event " is different in Implementation plan as compared to Standard (Implementation Plan does not include phrase "The 80% threshold may be reduced upon written notification to the Regional Entity.") The Applicability section in the Implementation Plan is also different than the Standard.

Organization	Yes or No	Question 1 Comment
Response: Thanks for the catch, the Standard is correct and the implementation plan will be revised to match the Standard.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SERC OC Standards Review Group	Yes	
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	
ERCOT	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
SMUD	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Keen Resources Ltd.	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	

2. The BARC SDT has modified the current definition for Contingency Reserve. Do you agree that the modified definition provides for greater clarity? If not, please explain in the comment area below.

Summary Consideration: The majority of negative commenters did not agree that the definition need to be modified. The SDT explained that they felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard.

Many commenters question why the SDT included Demand Side Management (DSM) in the definition. The SDT stated that they included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.

Organization	Yes or No	Question 2 Comment
Northeast Power Coodinating Council	No	The last sentence in the definition is not needed, and should be removed. "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." is the "How" to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence.
Response: Thank you for your comments. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
MRO NERC Standards Review Forum	No	The presently approved NERC definition for contingency seems adequate for this standard. If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.
Response: Thank you for your comments. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	No	As written there is no distinction as to whether 'unloaded generation' is on-line or off-line generation. Which is it, or is it both? Additional clarification here would be helpful.
Response: Thank you for your comment. Contingency reserve can be both on-line or off-line generation provided it meets the requirements of the particular Standard in question.		
Duke Energy	No	We would be in agreement except that it includes the term "Balancing Contingency Event", and we would need our above suggested changes made to that definition to be in agreement here.
Response: Thank you for your comment. The SDT believes that it addressed your concerns with the modifications that have been made to the definition of Balancing Contingency Event.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates believe the proposed modifications actually introduce ambiguity and error. Attempting to provide examples (such as...) in definitions is ill-advised as this adds ambiguity to the definition as the list may be considered all inclusive by some and not by others. The final sentence should be struck. As defined by NERC, Demand Side Management includes "all activities" used to "influence" energy usage, which includes programs such as time of day rates, light bulb replacement, and other efficiency programs which do not provide controllable capacity. It appears the SDT may have intended to include the NERC defined term Direct Control Load Management as an example, however, examples need not be included in definitions.
Response: Thank-you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
MISO Standards Collaborators	No	The presently approved NERC definition for contingency seems adequate for this

Organization	Yes or No	Question 2 Comment
		standard.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
ACES Standards Collaborators	No	Please strike the last sentence of the definition. It is an explanation of what may constitute contingency reserve and is not actually part of the definition. It should be included in the background document. We understand the reason for the inclusion may be in response to a directive to further the Commission's policy on expanding the use of DSM. However, the use of DSM has expanded significantly since the directives were issued and could be said to have been "overcome" by events. It is well understood within this industry that DSM may be used as a resource. The drafting team could include an explanation in the application guidelines or the background document that would explain that DSM could be used among other resources.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
IRC-SRC	No	The presently approved NERC definition for contingency reserve seems adequate for this standard.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
Independent Electricity System Operator	No	We generally agree with the revised definition, but do not see the need for the last sentence: "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." This is the

Organization	Yes or No	Question 2 Comment
		"How's" to meet the contingency reserve requirement, which does not belong to a definition. We suggest to remove this sentence.
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
ISO New England Inc.	No	The last sentence in the definition is not needed, and should be removed. "The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." is the "How" to meet the contingency reserve requirement, which does not belong in a definition. Suggest to remove this sentence. Because of the nature of using hourly integrated values, Requirement R2 may not provide Operators on shift with sufficient information in a timely manner. We recommend an alternative that uses a timer that begins to count up when the BA becomes deficient in contingency reserve, resulting in a compliance violation should the condition persist for 105 minutes. Also, as proposed, it may be create burdensome reporting requirements so that an hourly shortfall can be dismissed due to Balancing Contingency Events, for example.
Response: Thank you for your comments. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive. **It is not clear to the SDT how an operator that uses hourly integrated values would meet the current BAL-002 Standard in effect. R2 is similar to the current requirement R3.1 except that it clarifies that during periods of a "Contingency Event Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert Level 2 or 3", an entity does not need to maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.**		
American Electric Power	No	It is not clear exactly what "other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3)" refers to.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. Other standards, such as EOP-002-3.1 refer to deploying Operating Reserve during EEA 1 or EEA 2. This is an acknowledgement that Contingency Reserve can be deployed as a part of Operating Reserve as allowed in the specific requirements of the various NERC Standards.		
Keen Resources Ltd.	No	The definition is left vague, to enable "double counting" of reserve types. It is a definition not of reserve "allocated" to contingency/restoration, but of reserve that is "usable" for contingency/restoration and which includes the two other defined types of reserve, Frequency Responsive and Regulating. This distinction, between "usable" and "allocated" remains notoriously unclear in this definition, and in apparent contradiction to the provision against double-counting of reserve in the "Guidance Document" currently in preparation. To make the distinction clear, and that occasional "double counting" of reserve types is specifically being allowed by the BAL performance standards, this definition needs to be broken into two definitions. The term "Contingency Reserve" defined in the current definition should be changed to "Reserve Usable for Contingencies" which should be the term used in requirement R2. A second, clear definition of "Contingency Reserve" should be made for use in the Guidance Document, as reserve "allocated" for contingency/restoration, and the term "Contingency Reserve" should thereby be made clearly usable in that document's admonition against double counting of the three types of reserve: Frequency Responsive, Regulating, and Contingency.
Response: Thank you for your comments. The SDT has discussed your comments and will leave the definition as is, except for removing the final sentence as noted in previous responses. **The SDT does not believe that Contingency Reserve should include other types of reserve.** **Double counting is not allowed in the Standard. While during real time deployment of Contingency Reserve, the portfolio of Operating Reserve may be deployed for the contingency, resulting in a potential temporary deficiency of Regulating or Frequency Responsive reserve, the total amount of required Operating Reserve should remain the same.**		

Organization	Yes or No	Question 2 Comment
The SDT feels that additional definitions are unnecessary.		
ERCOT	Yes	ERCOT ISO suggests that the SDT consider the following changes so that the definition of the Contingency Reserve clearly accommodates resources eligible under the respective BA rules to provide Contingency Reserve for that BA: "The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by 'resources eligible under the respective BA rules, including, but not limited to,' resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation."
Response: Thank you for your comment. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as stated in the EOP-002 Standard. The SDT included DSM to clarify that DSM may be included as Contingency Reserve in response to the FERC directive.		
Salt River Project	Yes	This standard is a big improvement over the existing standard because it provides much needed formal definitions of many terms that are used but not currently defined in BAL-002-1, the definition of Contingency Event, Contingency Reserve and MSSC being three of them.
Response: Thank you for your comment and support.		
Texas Reliability Entity	Yes	The Contingency Reserve definition should mention a Reserve Sharing Group in addition to a BA.
Response: Thank you for your comment. The SDT understands your concern, but does not believe the addition of the RSG in the definition would add to the meaning since RSGs are a grouping of BAs.		
Xcel Energy	Yes	If the DCS definition will not be used any longer, recommend the team retire it from the NERC glossary.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The SDT believes that the term DCS may be used in other standards. If it is not the SDT will look into retiring the definition.		
Manitoba Hydro	Yes	No comment.
SERC OC Standards Review Group	Yes	
seattle city light	Yes	
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	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Quebec TransEnergie	Yes	

3. **The BARC SDT has created a definition for Reserve Sharing Group Reporting ACE. Do you agree with this definition? If not, please explain in the comment area below.**

Summary Consideration: Many of the commenters did not believe that it was necessary to create a definition for Reserve Sharing Group Reporting ACE. The SDT explained that since the standard used the term Responsible Entity, it required the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.

Several commenters stated that the definition should only apply to BAs participating in the RSG at the time of the event. The SDT agreed with their comment and modified the definition to state this and provide additional clarity.

Organization	Yes or No	Question 3 Comment
Northeast Power Coodinating Council	No	There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
SPP Standards Review Group	No	Do you need to add '...at the time of the measurement' at the end of the definition?
Response: Thank you for your comment. The SDT has made the necessary change.		
SERC OC Standards Review Group	No	The definition should only include the BAs that were participating in the event.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
Duke Energy	No	Only BA's participating in response to an event should be included in the Reserve Sharing Group Reporting ACE calculation. As we commented on BAL-001-2, ACE should be fully defined in a manner where Reporting ACE can be defined simply as the "The scan rate values of a Balancing Authority's ACE".
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates believe the definition should include only those BAs participating in the specific event, not simply all BAs that are members of the RSG. Suggest revising the definition as follows: -- Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that are participating in the Balancing Contingency Event. --
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
MISO Standards Collaborators	No	This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	No	The definition should include only the BAs asked to participate in the reserve recovery event.

Organization	Yes or No	Question 3 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
ACES Standards Collaborators	No	We believe the definition as proposed is already a common understanding and is not needed. We simply do not see how it adds value. Further, having multiple definitions for ACE creates confusion and is simply not needed.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
IRC-SRC	No	This change was not proposed in the drafting team's SAR and we see no FERC directive to make this change. RSGs have measurement processes that have worked well for quite some time. If the drafting team has guidance on the measurement process, that should be put in a supporting document rather than hard-coding additional obligations in the standard.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
PJM Interconnection, LLC	No	The definition should only include the BA's participating in the event.
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	We do not see the need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the standard at all. On the other hand, if the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the standard is not explicit or complete to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Energy Mark, Inc.	No	The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is.
Response: Thank you for your comment. The drafting team suggests that you intended to say "Reporting ACE" since "Reportable ACE" has not been proposed as a new definition. We agree with you suggestion, that the proposed definition of "Reporting ACE" should be included in both this standard and BAL-001-2 until it is approved and included in the Glossary and used consistently throughout.		
ISO New England Inc.	No	There is no need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the Standard at all. If the RSG is obligated to meet the DCS requirement and needs to return its ACE to zero or the Preâ€Reportable Contingency Event value, then the Standard is not explicit nor complete enough to place this obligation on the RSG.
Response: Thank you for your comment. The use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition.		
Seminole Electric Cooperative, Inc.	No	As written, it arbitrarily precludes the calculation of an RSG ACE for an entire RSG based upon the aggregate frequency bias, and the RSG participants' net interchange with non-participants. The Florida Reserve Sharing Group monitors participants'

Organization	Yes or No	Question 3 Comment
		individual ACE, but calculates an RSG ACE based on the aggregate frequency biases and net interchange with non-participants.
Response: Thank you for your comment. The SDT has modified the definition to provide clarity and address your concern.		
Modesto Irrigation District	No	It is in conflict with the very definiton of a balancing authority.
Response: Thank you for your comment. Unfortunately, the SDT would need additional information to provide a response to your comment.		
seattle city light	Yes	Note there are differing reference to Regulating Reserve Sharing Group and Reserve Sharing Group BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the standards.
Response: Thank you for your comment. The SDT has corrected this and is now using a single term.		
Avista	Yes	The assumption is made that algebraic sum of the ACE's is as follows:Reserve Sharing Group Reporting ACE = ACE(BA1) + ACE(BA2) + ACE(BA3) + ...An example calculation would be helpful and provide clarity.
Response: Thank you for your comment. The SDT has modified the definition to provide additional clarity as to how it is calculated.		
Salt River Project	Yes	Same comment as for #2.
Manitoba Hydro	Yes	No comment.
MRO NERC Standards Review Forum	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 3 Comment
Administration		
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Portland General Electric Company	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	
Xcel Energy	Yes	

4. The BARC SDT has added language to the proposed requirements in the standard and to the definition for Contingency Reserve to resolve any conflicts between this standard and the EOP standards. Do you agree that this modification was necessary and that any possible issues are now resolved? If not, please explain in the comment area.

Summary Consideration: Several commenters felt that there should only be a statement in the applicability section stating that this standard did not apply to a BA when it was in a EEA Level 2 or 3. The SDT explained that they included it in the applicability section and in the requirement in order to assure no misinterpretation by the auditors.

A few commenters felt that this standard blurred the current "clear and well-established criteria" of what triggers a DCS event. The SDT stated that they disagreed that a "well-established criteria of what triggers the DCS event" is defined, and attempted to provide a more specific definition. NERC definition of a Disturbance also is not clear and well defined. What is defined is in the eye of the auditor, and the drafting team believes it has provided more granularity and specificity.

Organization	Yes or No	Question 4 Comment
MRO NERC Standards Review Forum	No	All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by the auditors.		
PPL NERC Registered Affiliates	No	The PPL NERC Registered Affiliates do not agree with the proposed modifications to the NERC defined term Contingency Reserve as explained in our comment 2.
Response: Thank you for your comment. The drafting team understands your comment associated with Question No. 2, however, the drafting team is not sure as to the meaning of your comment as it pertains to Question No. 4. The SDT felt it was important to update the definition to clearly state that it was for a Balancing Contingency Event, as well as for use during EEA Levels 2 or 3, as		

Organization	Yes or No	Question 4 Comment
stated in the EOP-002 Standard.		
MISO Standards Collaborators	No	It needs a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by the auditors.		
ACES Standards Collaborators	No	(1) We do believe that it is helpful to clarify that a BA does not have to comply with recovering ACE and contingency reserves when it is in an EEA 2 or 3. It certainly would not make sense to go to the extreme of shedding firm load to recover ACE or contingency reserves if a BA was simply out of balance with no transmission security issues, system frequency issues or stability issues. There are standards requirements such as operating within IROLs/SOLs that would deal with these other reliability issues and provide the indication if load needed to be shed to address the deficient BA. A more efficient way to address this issue may be to apply the restriction in the applicability section. (2) It would be helpful if the drafting team explained what the conflicts with the EOP standards are. Besides the one identified above, are there others? The background document states that there are conflicts but does not explain them. It is difficult to judge if the issue was addressed without an adequate explanation.
Response: Thank you for your comment. **1) The drafting team included it in both locations in order to assure no misinterpretation by the auditors.** **2) The drafting team will provide more explanation within the background document**		
IRC-SRC	No	All that's needed is a simple statement in the applicability section that the standard does not apply to BAs when they are in EEA 2 or 3.
Response: Thank you for your comment. The drafting team included it in both locations in order to assure no misinterpretation by		

Organization	Yes or No	Question 4 Comment
the auditors.		
ReliabilityFirst	No	a. ReliabilityFirst recommends removing any references to “an Energy Emergency Alert Level 2 or Level 3” since these are not defined terms (Energy Emergency Alert Levels are only noted in Attachment 1, EOP-002-3). ReliabilityFirst believes the BAL-002-2 should stand on its own merit and not rely on conditions within an attachment within another standard. For example, if the Energy Emergency Alert levels designations ever change in the future, this has the potential to have an impact on the intent of the BAL-002-2 standard. For consideration, ReliabilityFirst recommends defining the alert levels within the standard itself as an attachment, hence not relying on another standard for these conditions.
Response: Thank you for your comment. The drafting team has modified the standard to provide additional clarity.		
American Electric Power	No	Please see our response to Q2 in regards to the definition of Contingency Reserve. AEP disagrees with the second half of R1 where it begins with “or... Its Preâ€Reportable Contingency Event ACE Value, (if its Preâ€Reportable Contingency Event ACE Value was negative)...” . The language provided in this section and its sub-bullets are extremely confusing. It appears that the intent is to set an expectation for recovering from multiple contingency events, however the language provided is unnecessarily complex and will likely confuse those responsible for meeting the requirements.
Response: Thank you for your comment. Your comments do not address the specific Question No. 4, however, the drafting team has provided a calculator to perform the calculation and the Background Document to help resolve your conflict.		
Keen Resources Ltd.	No	You mean not "possible issues" but "possible issues related to EOP standards". Otherwise, see answer to question 2 about other issues.
Response: Thank you for your comment. The drafting team has incorporated your suggestion.		

Organization	Yes or No	Question 4 Comment
seattle city light	Yes	This standard is an improvement over the existing BAL-002 because it clarifies the requirements for a Balancing Authority or Reserve Sharing Group regarding Contingency Reserve requirements during Energy Emergency Alerts.
Response: Thank you for your comment.		
Duke Energy	Yes	We agree with the change to R1 to recognize emergency operations as long as the BAAL is implemented in BAL-001-2, as it is the only viable standard for measuring real-time performance and the BA's impact on Interconnection frequency during such operation. Duke Energy agrees that the proposed language in this standard will allow the BA to utilize its contingency reserves to continue to serve load under an Energy Emergency Alert Level 2 or Level 3 while remaining compliant to BAL-002; however under what circumstances, if any, should the Balancing Authority shed firm load as a last resort to ensure that it remains compliant to Requirement R1 under normal operations? In our opinion, the inability of a Balancing Authority to meet the 15-minute DCS compliance threshold does not in itself represent a reliability issue. There are cases in the off-peak times especially where the recovery is detrimental to Interconnection frequency. Some of the revisions in BAL-002-2 blur the clear and well-established criteria of what triggers the DCS event. Too much is left up to after-the fact compliance scrutiny, and operators need unquestionable guidance on this matter. Also, in the definition of Contingency Reserve, add the word "NERC" before the word "contingency" for clarity.
Response: Thank you for your comment. The drafting team does not agree that a "well-established criteria of what triggers the DCS event" is defined, and attempted to provide a more specific definition. NERC definition of a Disturbance also is not clear and well defined. The drafting team believes it has provided more granularity and specificity.		
Texas Reliability Entity	Yes	R2- Disturbance Recovery Period is not defined and should be changed to Contingency Event Recovery Period.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The drafting team has made the necessary corrections to address your concern.		
Avista	Yes	This language clarifies that when in an Energy Alert 2 or 3, the BA is using all available reserves to maintain ACE.
Response: Thank you for your comment.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
SERC OC Standards Review Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
SMUD	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 4 Comment
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Quebec TransEnergie	Yes	

5. The BARC SDT has developed Requirement R2 which requires entities to have Contingency Reserve at least equal to its MSSC. This requirement was added to address, in conjunction with Requirement R1, the FERC Directive for a continent wide Contingency Reserve policy. Do you agree that this addresses the FERC Directive? If not, please explain in the comment area.

Summary Consideration: Many commenters felt that BAs may withhold their Contingency Reserve from events other than reportable events so that they always have the necessary reserve obligation. The SDT stated that the present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

Several commenters stated that the old Policy 1 noted many reasons for operating reserves and that a BA may be reluctant to deploy its reserves since it could start the clock on the available hours. The SDT explained that they agreed that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.

A few of the commenters believed that the standard was a commodity standard and was not performance based. The SDT stated that they had modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.

Some commenters believed that there was a embedded expectation to recover from and measure multi-contingent events beyond MSSC. The SDT explained that they believed that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.

A couple of commenters asked the SDT to develop a reserve policy. The SDT stated that they were developing a Operating Reserve Guideline to be presented to the NERC OC for acceptance at their September 2013 meeting.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock Please clarify. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Please clarify. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. Is the SDT stating that recovery is needed to recover to zero or MSSC? We believe the way a way to achieve the Commissions directive for a continent wide

Organization	Yes or No	Question 5 Comment
		policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
SERC OC Standards Review Group	No	This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need.The first

Organization	Yes or No	Question 5 Comment
		unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe a way to achieve the Commissions directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We agree with the principle of a BA maintaining contingency reserves to respond to its MSSC. However, as R2 is currently proposed it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures and VSL, we believe that the requirement needs to stand on its own and that the

Organization	Yes or No	Question 5 Comment
		specifying language should be included in R2 itself.
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
seattle city light	No	Seattle City Light finds Requirement R2 and Measure M2 to lack specificity as to what level of performance is required for compliance, and recommends the following changes:"R2. Each Responsible Entity shall maintain an amount of Contingency Reserve such that its clock-minute average of Contingency Reserves is equal or greater than the Most Severe Single Contingency except during the Disturbance Recovery Period and Contingency Reserve Recovery Period, or during an Energy Emergency Alert 2 or 3.""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 hard copy or electronic format) to demonstrate compliance with Requirement R2."

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.		
Duke Energy	No	Requirement R1 and R2 could provide a consistent continent-wide Contingency Reserve policy if the definition of Balancing Contingency Event provided a "bright line" to the industry on what events would be applicable to the determination of MSSC; we believe that Subsection "C." of that definition should be deleted, per our comment under question #1 above, and if the R2 allowed for other use of Contingency Reserves. Requirement 2 refers to "Disturbance Recovery Period" and "Contingency Reserve Recovery Period" which are no longer defined. Duke Energy would suggest the following change: "Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an hourly average amount of Contingency Reserve at least equal to its Most Severe Single Contingency." Language in Requirement R2 should also recognize that Contingency Reserves may be used from time to time to aid in balancing aside from the loss of resource - today such use takes places and does not impact compliance under DCS.Measure M2 requires that the Contingency Reserve averaged over each clock hour is greater than or equal to the amounts identified in Requirement 2 - however, as the amounts identified in Requirement R2 are allowed to be less than MSSC, it is not clear why the language at the end places an exception only on the 105-minute combined recovery and restoration period, and not on any period such resources may be utilized under an EEA2 or EEA3. Duke Energy would suggest modifying Measure M2 to read at the end "except during

Organization	Yes or No	Question 5 Comment
		an Energy Emergency Alert Level 2 or Level 3, or within the first 105 minutes following an event requiring the activation of Contingency Reserve." Though an hourly average is proposed, it is not practical for a BA to track its Contingency Reserves in a manner where it would make the choice to increase its Contingency Reserves above the MSSC if it happened to drop below its MSSC for some time in the same hour - it is an unnecessary activity to bring into real-time operations. Also, we believe the Standard Drafting Team should carefully check to make certain that these new definitions don't impact other existing definitions. Though suggestions have been provided, Duke Energy does not support the adoption of Requirement R2 and agrees with the comments provided by MISO. Performance under the existing BAL-002 has been stellar without the need for an additional requirement to track Contingency Reserves to the extent prescribed. The current DCS is a very effective results-based standard. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability.

Response: Thank you for your comment.

[1] The SDT has made further modifications to the definition and believes that these modifications provide sufficient clarity.

[2] The SDT has made the necessary correction.

[3] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

[4] The SDT disagrees with your comment. The exception does cover EEA Levels 2 and 3. However, the SDT has modified the standard to provide additional clarity.

Organization	Yes or No	Question 5 Comment
[5] The SDT has modified the requirement and measure and believes that the modifications provide the necessary clarity. **[6] The SDT believes that this calculation can be easily accomplished in most standard EMS. The value provided to the System Operator through heightened situational awareness is worth the effort.** **[7] The SDT has checked and believes there are no conflicts.** **[8] We believe that the proposed standard clarifies the intent of the current standard.**		
PPL NERC Registered Affiliates	No	PPL NERC Registered Affiliates do not agree that the development of additional requirements is necessary to meet the FERC directive for a continent wide policy. Additional comments on this topic provided under question 10.
Response: Thank you for your comment. **The SDT has decreased the number of requirements and provided additional clarity. The essence of the proposed R1 and R2 still encompass the intent of the current BAL-002.**		
MISO Standards Collaborators	No	R2 has nothing to do with a Continent Wide Contingency Reserve Policy and there is nothing in the drafting team's SAR that calls for the implementation of a commodity standard. This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate

Organization	Yes or No	Question 5 Comment
		performance under Policy 1. The last most significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR nor in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. A fundamental flaw in R2 is that drafting team has implemented a commodity expectation that the BA must have contingency reserves above MSSC at all times and yet has provided no clear definition on how this is measured (does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What type of proof of deliverability is required? Some of the background information implies that frequency responsive resources must be removed from the Contingency Reserve calculation. How much? All headroom? Enough to provide the IFRO?This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the ultimate demonstration of adequacy.We believe the way a way to achieve the Commissions directive for a continent wide "contingency reserve" policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The document the drafting team is working on is a good start. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement

Organization	Yes or No	Question 5 Comment
		reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.
Response: Thank you for your comment. **[1] The SDT has modified the existing standard by eliminating administrative requirements. However, they have maintained requirements associated with performance and addressed the FERC directive in order 693.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves.** **[4] The SDT does not believe that they have excluded anything that is in the present standard with regards to what would count as contingency reserve but has in actuality provided clarity to the present wording in the current BAL-002.** **[5] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[6] The SDT believes that this is outside the scope of the current SAR.**		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	The proposed requirement would have significant negative consequences as Reserves are an inventory intended to be used when there is a reliability need.A BA could be encouraged to never deploy their CRs except for during a DCS-reportable event. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the time would start ticking on the ‘available hours’

Organization	Yes or No	Question 5 Comment
Company Generation; Southern Company Generation and Energy Marketing		clock. Additionally, BAs that don't withhold CRs for non-DCS events might feel the need to increase the amount of contingencies they carry in order to always have more reserves than their MSSC which in turn, would increase customer costs without a demonstrated need. We suggest that not all BAs have the same needs for the various types of operating reserves and that performance is the demonstration of adequacy. We suggest the SDT work with the NERC OC to create a policy document that outlines the factors the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves and provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standard's process, we suggest that NERC add these four types of reserves to 'Attachment 1-TOP-005 Electric System Reliability data" with the noted expectation that RCs collect this information in real time for use in the EEA process. While we agree with the principle of a BA maintaining Contingency Reserves to respond to its MSSC, the proposed R2 puts the BA at risk if CR reserves fall below its MSSC for any single sampling period. For example, BAs with a 2 second sampling interval would be at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the proposed Measures and VSLs, we suggest that specific language be included in R2 and not just in the Measure (SERC OC). A reference to the integrated clock hour should be included in R2 as in the Measure.

Response: Thank you for your comment.

[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.

Organization	Yes or No	Question 5 Comment
[2] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves. **[3] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[4] The SDT believes that this is outside the scope of the current SAR.** **[5] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.**		
ACES Standards Collaborators	No	(1) We are concerned that this requirement will have unintended consequences. As written, a BA will be forced to only deploy contingency reserve for responding to resource contingencies. Consequently, the BA will have to carry more operating reserves which increases their operating costs tremendously without commensurate reliability benefit. Furthermore, there is no data indicating that operating reserves carried by BAs today are insufficient. (2) While contingency reserve is just one type of operating reserve and is intended for use to respond to contingent events, a BA should not be restricted to deploying it only for contingent events. There may be other reasons for a BA to have a large negative ACE (i.e. units don't ramp as expected) and the BA should be free to call upon its contingency reserve to recover ACE in such a situation. Since the FERC directive that is driving this requirement is to establish a continent wide policy on contingency reserve, a better solution would be for NERC to write an operating policy describing appropriate uses of various types of contingency reserves. A guideline document would provide better details for an operating policy than a requirement.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
[1] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility. **[2] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[3] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.**		
IRC-SRC	No	We believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for a DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies the carry so they always have more reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The last significant unintended consequence relates to the embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn’t in the drafting team’s SAR or in a directive. Events greater than MSSC should be reported,

Organization	Yes or No	Question 5 Comment
		but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. This proposal sets a commodity standard which is not in keeping with the superior approach of having performance-based standards. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of adequacy. We believe the way a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process (this was the directive in 693), NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process.

Response: Thank you for your comment.

1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.

[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.

Organization	Yes or No	Question 5 Comment
[3] The SDT believes that Requirement R1 as written requires deployment of Contingency Reserve up to MSSC, however, the responsible entity must meet all of the other NERC Reliability Standards to meet its reliability obligation which may involve the deployment of Regulating or frequency responsive reserves. **[4] The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693** **[5] The SDT is drafting a Reserve Policy Guideline for consideration by the NERC Operating Committee.**		
PJM Interconnection, LLC	No	PJM agrees with the principle of a BA maintaining contingency reserves to respond to its MSSC but believe this requirement would have negative unintended consequences. Reserves should be used when there is a reliability need that may or may not be caused by the loss of a resource. This requirement encourages BA's to withhold deployment of contingency reserves except for DCS reportable disturbances. For example, if a BA's ACE is dragging into the top of the hour, along with Interconnection frequency, due to schedule changes and slow unit response, this requirement incentivizes the BA to withhold deploying reserves. If a BA is approaching an IROL that could be mitigated by deploying contingency reserves, this requirement penalizes the BA for doing so, even though the result would benefit the Interconnection. Even if PJM agreed with the proposed R2, which we do not, as written it puts the BA at risk if contingency reserves fall below its MSSC for any single sampling period. Indeed, as stated it puts a BA with a 2 second sampling interval at greater risk than a BA with a 6 second sampling interval. While the SDT has attempted to resolve this issue in the Measures, specifically M2, PJM believes that the requirement needs to stand on its own and that the specifying language should be included in R2 itself. DCS performance in North America has been greatly improved compared to what was considered adequate performance under Policy 1. Not all BAs have the same needs for the various types of operating reserves. Performance is the demonstration of

Organization	Yes or No	Question 5 Comment
		adequacy. We believe a way to achieve the Commission's directive for a continent wide policy is for the drafting team, in concert with the NERC operating committee, to create a policy document that outlines the factors that the BA uses in performing an assessment of needed frequency responsive, regulating and contingency reserves. The policy should provide simple definitions for frequency responsive, regulating, contingency, and replacement reserves. Once the policy has undergone comment through the standards process, as was a directive in 693), NERC could add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data".
Response: Thank you for your comment. **[1] The SDT agrees with your statement that Policy 1 had many reasons for operating reserve. BAL-002 addresses the reason for Contingency Reserve to be used during a Balancing Contingency Event. If a BA elects to use its Contingency Reserve for other purposes it does trigger the clock ticking on the available hours. Additionally R2 is necessary to fulfill the directive from FERC Order 693 to establish a continent wide Contingency Reserve policy.** **[2] The present standard requires a responsible entity to hold contingency reserve at least equal to its most severe single contingency. While the recommended change by the SDT does not change the amount of Contingency Reserve being held, it does require the amount to be monitored at all times. The SDT believes the 99.77% performance expectation per calendar quarter (averaged over each clock hour) provides the responsible entity a reasonable period of flexibility.** **[3] The SDT cannot agree or disagree with your comment concerning DCS performance, but does agree that not all BAs have the same needs.** **[4] The SDT is developing a proposed Reserve Policy Guideline for the NERC OC consideration by the NERC OC.** **[5] The SDT believes that this is outside the scope of the current SAR.**		
Alberta Electric System Operator	No	Please consider revising requirement R2 to use the proposed new definitions as follows:R2. Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3, each

Organization	Yes or No	Question 5 Comment
		Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. [Violation Risk Factor: Medium] [Time Horizon: Realâ€time Operations]
Response: Thank you for your comment. The SDT has made the necessary corrections.		
Energy Mark, Inc.	No	I believe that this requirement falls under Paragraph 81 and should not be in the standard.
Response: Thank you for your comment. The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.		
Keen Resources Ltd.	No	As explained in my Comment to Question 2, the commonly used term "Contingency Reserve" needs to be unpacked into two terms: "Contingency Reserve" (to be used in the "Guidance Document" currently being prepared) and "Reserve Usable for Contingencies" (to be used in this standard instead of "Contingency Reserve"). The FERC Directive 693 did not identify and sort out this ambiguity and called simply for a requirement of undifferentiated "response" to a contingency, without distinguishing between the three intrinsic "types" of response, namely Frequency Response, Regulating Response, and Contingency Response, except to designate the "objective"/cause of the Response. All three types of response can meet that objective. The FERC Directive then sought to expand the definition of Contingency Reserve to include demand-side resources, and to set the requirement of a quantity of "Contingency Reserve", without specifying "Contingency Reserve" as any particular reserve type. So, yes, R2 does address the FERC Directive, but the FERC Directive is itself inadequate for failing to make the all-important distinction between type of reserve, and usability of different reserve types to meet a single reliability objective which would be some generalized "Responding" to a "Contingency" without specifying the "type" of response which distinguishes reserve types. Rather than simply "address" a technically uninformed FERC Directive, NERC should in its superior

Organization	Yes or No	Question 5 Comment
		reliability wisdom/competence seek to improve upon the FERC Directive and establish the precedent that FERC takes technical direction from NERC, not the other way around and without opposing or contradicting FERC.
Response: Thank you for your comment. **The SDT has reviewed your suggested modification to the definitions, but feel that the current definitions, as presently modified, provide for sufficient clarity.** **The SDT is developing a Reserve Policy Guideline for consideration by the NERC OC that will address the concern you have identified in a different manner.**		
Seminole Electric Cooperative, Inc.	No	This standard ahs been and should continue to be results based. R2 imposes a tracking and evidentiary requirement which is unreasonable and is not warranted by past performance and results. If the logical next step to be standards proscribing the measurement, qualification, etc. for contingency reserves?
Response: Thank you for your comment. The SDT modified the existing standard by eliminating administrative requirements, however, they have maintained requirements associated with performance and addressed the FERC directive in order 693.		
Texas Reliability Entity	Yes	A Responsible Entity may have an internal Contingency Reserve policy that is different than the proposed language in R2. While we understand the R2 states the minimum Contingency Reserve amount, should R2 be re-worded to state that each Responsible Entity shall maintain an amount of Contingency Reserve as least equal to its Most Severe Single Contingency or an amount per its Contingency Reserve policy, whichever is larger? Ex. The MSSC in ERCOT is 1375 MW, but the required minimum responsive reserve is 2300 MW, which is the amount necessary to maintain adequate primary frequency response to meet the intent of the BAL-003 standard.
Response: Thank you for your comment. The SDT is only requiring a minimum amount of Contingency Reserve to be available. There is nothing in the standard to preclude an entity to carry additional Contingency Reserve.		

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
SMUD	Yes	

Organization	Yes or No	Question 5 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Modesto Irrigation District	Yes	
Hydro-Quebec TransEnergie	Yes	

6. The BARC SDT has assigned both Requirement R1 and Requirement R2 a "medium" VRF. Do you agree with the proposed VRF? If not, please explain in the comment area below.

Summary Consideration: The majority of the negative commenters did not agree with the requirements and therefore could not agree with the VRFs. The SDT explained that they could not determine from the comment what they believed to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.

Organization	Yes or No	Question 6 Comment
MRO NERC Standards Review Forum	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
SERC OC Standards Review Group	No	It is difficult to agree with the VRF's while disagreeing with the standard as proposed.
Response: Thank you for your comment. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified		

Organization	Yes or No	Question 6 Comment
emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
Duke Energy	No	We can't agree, due to the current lack of clarity in the requirements.
Response: Thank you for your comment. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
MISO Standards Collaborators	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
ACES Standards Collaborators	No	We agree with the VRF for requirement R1 but do not agree with requirement R2 as written. Thus, we do not agree with the VRF for Requirement R2.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be incorrect. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
IRC-SRC	No	We believe the requirement itself is inappropriate, so any VRF is unnecessary.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event.		

Organization	Yes or No	Question 6 Comment
This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
Seminole Electric Cooperative, Inc.	No	Agree with the the VRF for R1, but not R2 for the reasoons described in response to Question 6.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be incorrect. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		
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	It is difficult to agree with the VRFs while disagreeing with the standard as proposed.
Response: Thank you for your comment. The SDT cannot determine from your comment what you believe to be unnecessary. Requirement R1 clarifies the requirement to return ACE to specified values following a reportable balancing contingency event. This requirement already exists in the existing standard. Requirement R2 establishes the requirement to operate with Contingency Reserve at least equal to the most severe single contingency, except for during specified emergency operations conditions. This requirement exists in existing standards, but without a clear definition of "most severe single contingency". The SDT has clarified the definition and the Requirement.		

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
SPP Standards Review Group	Yes	
seattle city light	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 6 Comment
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

7. The BARC SDT has assigned both Requirement R1 and Requirement R2 a Time Horizon of "Real-time Operations". Do you agree with the Time Horizon the SDT has chosen? If not, please explain in the comment area below.

Summary Consideration: The vast majority of the commenters agreed with the use of "Real-time Operations" as the appropriate time horizon.

Organization	Yes or No	Question 7 Comment
Seminole Electric Cooperative, Inc.	No	Same response as Question 6.
Response: Thank you for your comment. Please refer to our response to Question #6.		
Modesto Irrigation District	No	
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
SPP Standards Review Group	Yes	
SERC OC Standards Review Group	Yes	

Organization	Yes or No	Question 7 Comment
seattle city light	Yes	
Duke Energy	Yes	
MISO Standards Collaborators	Yes	
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	
ERCOT	Yes	
ACES Standards Collaborators	Yes	
Oklahoma Gas & Electric	Yes	
IRC-SRC	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 7 Comment
Salt River Project	Yes	
PacifiCorp	Yes	
PJM Interconnection, LLC	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
ISO New England Inc.	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 7 Comment
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

8. The BARC SDT has developed VSLs for Requirement R1 and Requirement R2. Do you agree with the VSLs in this standard? If not, please explain in the comment area.

Summary Consideration: Many of the commenters disagreed with the use of an event by event measure. The SDT explained that currently in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.

Some commenters stated that the VSL implied that the entity had recovered from the event. The SDT agreed with the commenters and modified the VSL to use the term "partially recovered".

Organization	Yes or No	Question 8 Comment
MRO NERC Standards Review Forum	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
SPP Standards Review Group	No	Change all of the R1 VSLs to read 'The Responsible Entity partially recovered…'
Response: Thank you for your comment; the drafting team has incorporated your suggestion.		
SERC OC Standards Review Group	No	Requirement 1 should not be an event by event obligation. A quarterly average measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have		

Organization	Yes or No	Question 8 Comment
applied compliance and associated penalties on an event by event base.		
Duke Energy	No	We can't agree, due to the current lack of clarity in the requirements.
Response: Thank you for your comment. The SDT has modified the requirements to provide for additional clarity.		
MISO Standards Collaborators	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
ACES Standards Collaborators	No	We disagree with the VSLs for both requirements. The VSLs for requirement R1 raise the bar significantly for compliance without a technical justification. Today, DCS compliance is determined by a quarterly average of response to events. Thus, failure to recover ACE for two events within the same quarter would be a singular violation. As proposed, the new VSLs would treat each event as a separate violation. Without significant justification, we cannot agree with this change to the VSLs. Because we do not agree with Requirement R2, we do not agree with the corresponding VSLs.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		
IRC-SRC	No	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base.		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	BPA recommends changing the VSLs for R2 to: Lower VSL more than 2 but less than or equal to 5 hours; Moderate VSL more than 5 but less than or equal to 10 hours; High VSL more than 10 but less than or equal to 15 hours; Severe VSL More than 15 hours.
Response: Thank you for your comments. The SDT believes that the current ranges in the VSL for R2 are more appropriate.		
PJM Interconnection, LLC	No	It is difficult to agree with the VSL's while disagreeing with the standard as proposed.
Response: Thank you for your comment.		
ReliabilityFirst	No	The VSLs for Requirement R2 references "each calendar quarter" while the actual requirement R2 does not require maintaining an amount of Contingency Reserve at least equal to its Most Severe Single Contingency on a quarterly basis. Also, the lower VSL starts with an entity being deficient for more than five hours. This poses a gap; if for example, an entity was deficient between one and four hours. ReliabilityFirst recommends restructuring the VSLs, to be consistent with the language in the requirement, as follows (this is an example of a Lower VSL); "The Responsible Entity maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency but its Contingency Reserve was deficient for less than or equal to 15 hours."
Response: Thank you for your comments. The drafting team has provided clarifying language.		
Tacoma Power	No	Tacoma Power does not understand - all levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100% in every case? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.
Response: Thank you for your comments. The drafting team has provided clarifying language.		

Organization	Yes or No	Question 8 Comment
Texas Reliability Entity	No	1) R1 VSL- At what point is the ACE measured in order to determine the % of required recovery. We assume it is the lowest ACE value measured during the one-minute period for the Balancing Contingency Event, but this should be clarified.2) R2 VSL - A deficiency less than 5 hours is not covered by the VSL. If the intent is to allow a certain amount of deficiency without penalty, that should be clearly stated in the requirement and not implied in the VSL.3) R2 VSL - Five hours in a calendar quarter of not having sufficient Contingency Reserves seems too long, especially since Contingency Event Recovery Periods and EEAs are excluded. We would recommend a shorter time frame, e.g. 0-3 hours for lower VSL, 3-5 for moderate VSL, 5-10 for high VSL, and >10 for severe VSL. Also, the time frame for each VSL level needs to state if it is cumulative or on a per-event basis (we assume it is cumulative but it should be explicitly stated).
Response: Thank you for your comments. The drafting team has provided clarifying language.		
Seminole Electric Cooperative, Inc.	No	
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	Requirement 1 should not be an event by event obligation. A quarterly measure has worked quite well. We disagree with the current R2 so we cannot offer a suggestion to improve its VSL.
Response: Thank you for your comment. Currently, in all NERC/FERC investigations of events involving DCS compliance, they		

Organization	Yes or No	Question 8 Comment
have applied compliance and associated penalties on an event by event base.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coodinating Council	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power	Yes	
Avista	Yes	
NV Energy	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Energy Mark, Inc.	Yes	

Organization	Yes or No	Question 8 Comment
Portland General Electric Company	Yes	
American Electric Power	Yes	
Keen Resources Ltd.	Yes	
Hydro-Quebec TransEnergie	Yes	

9. The BARC SDT has made significant modifications to the Background Document based on industry comments received. Do you agree that these modifications provide additional clarity as to the development of this standard? If not, please explain in the comment area.

Summary Consideration: Some of the commenters wanted additional information as to how the threshold of 500 MW was determined. The SDT explained that they had removed the 500 MW threshold for all Interconnections and was now using a threshold unique to each Interconnection. They further stated that they had added language to the Background Document to provide additional clarity on the thresholds.

Manu of the commenters stated that since they disagreed with the requirements then they could not agree with the Background Document. The SDT explained that they had made modifications to the requirements and added clarifying language to the Background Document.

Organization	Yes or No	Question 9 Comment
MRO NERC Standards Review Forum	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment.		
SPP Standards Review Group	No	We offer the following suggestions:Page 3 1st paragraph 2nd line - replace ‘They’ with ‘It’4th line - remove the hyphen in ‘15-minute’ 2nd paragraph1st line - remove space following ‘Policy’ and insert space after the period Page 4 1st paragraph under Contingency Reserve

Organization	Yes or No	Question 9 Comment
		2nd line - replace 'its' with 'their' 6th & 7th lines - be consistent with the hyphens in demand side management Page 5 Correct the text formatting for Requirement 1 Page 6 2nd paragraph Capitalize Contingency Reserve 3rd paragraph 1st line - delete space in R1 5th paragraph Reword the 2nd sentence to read: 'Reviewing the data, the drafting team decided to establish a single, continent-wide standard on the median value of generation loss.' Under Violation Severity Levels This needs to be rewritten. The VSLs are based solely on amount of recovery. The paragraph tries to include the sufficiency of response but it's not in the VSLs. Page 10 Last paragraph Needs to be rewritten; what's there refers to R1 not R2.
Response: Thank you for your comment. The drafting team has revised the background document incorporating the majority of you suggestions. **The SDT has modified the VSL to provide additional clarity.**		
SERC OC Standards Review Group	No	The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." We disagree with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, not matter how small, be included

Organization	Yes or No	Question 9 Comment
		in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believe that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method. We suggest that additional details be provided in the Background Document relating to the methodology for development of the reporting thresholds.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
PPL NERC Registered Affiliates	No	It is not clear to the PPL NERC Registered Affiliates why the SDT chose to use the loss of load (negative loss values included in the CERTS statistics) when determining the reportable threshold for BAL-002. The document fails to include the criteria that were used to define a “significant impact on frequency”.
Response: Thank you for your comment. The drafting team has incorporated your comment and modified the standard.		
MISO Standards Collaborators	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment. The SDT would need additional information to provide a response. The SDT has made significant modifications to the standard and the Background Document,		
Southern Company: Southern Company Services, Inc.;	No	The Background Document states on page 4 that “FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or

Organization	Yes or No	Question 9 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		contingency that causes a frequency deviation.” We disagree with this interpretation of the Commission’s directive. In Order 693 (P355) the Commission declined to define a ‘significant deviation as a frequency deviation of 20 mHz’, but instead directed the ERO ‘to define a significant deviation and a reportable event’. The Commission directed that ‘loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,’ must be taken into account when developing the aforementioned definitions. We believe that the Commission clearly did not intend that any event that causes a frequency deviation, no matter how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500 MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample. We question whether this is appropriate and believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.We suggest that additional details be provided in the background document relating to the methodology for development of the reporting thresholds.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
ACES Standards Collaborators	No	(1) The background document needs to explain the conflict between BAL-002 and EOP-002 in detail rather than just stating that a conflict exists. (2) There is a statement on page 5 just before the Rationale by Requirement section that there are other definitions that have been added or modified. An explanation of what these are would be helpful.

Organization	Yes or No	Question 9 Comment
		(3) The formulas starting on page 8 are overly complicated in an attempt to address the few situations where there are additional generator contingencies that occur shortly before or during the ACE recovery window. We suggest starting with simple formulas that consider that predominant situation where only one generator contingency occurs. Then build the more complicated formulas on that. It will be easier to explain. We also suggest using pictures to explain the formulas. For example, a graph showing the loss of a unit before and after the current contingency would help explain the formulas. The graph should include labels such as what ACE_BEST, ACE_PRE, and MEAS_CR_RESP are.
Response: Thank you for your comment. **1 & 2 - The drafting team has modified the background document attempting to address your issues.** **3 - The SDT understands your concern and that is why they have provided a spreadsheet to assist you in the calculation.**		
IRC-SRC	No	There first needs to be agreement on the requirements before there is concurrence with the background document.
Response: Thank you for your comment. The SDT would need additional information to provide a response. The SDT has made significant modifications to the standard and the Background Document.		
PJM Interconnection, LLC	No	The Background Document states on page 4 that "FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation." PJM disagrees with this interpretation of the Commission's directive. In Order 693 (P355) the Commission declined to define a 'significant deviation as a frequency deviation of 20 mHz', but instead directed the ERO 'to define a significant deviation and a reportable event'. The Commission directed that 'loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances,' must be taken into account when developing the aforementioned definitions. PJM believes that the Commission clearly did not intend that any event that causes a frequency deviation, not matter

Organization	Yes or No	Question 9 Comment
		how small, be included in DCS reporting, but rather that a significant frequency deviation be defined by the ERO. The definition of a Reportable Balancing Contingency Event should, but currently does not, reflect such a definition. The Background Document on page 6 points to statistical frequency data supplied by CERTS in Attachment 1 to support the 500MW reporting threshold. While Attachment 1 shows the box plots used for this determination, it does not provide a narrative defining the sampling data or method. It appears that frequency deviations resulting from loss of load and loss of supply were included in the same data sample, skewing the results. PJM believes that in order for the industry to effectively evaluate the proposed criteria, a narrative needs to be added to Attachment 1 that explains the data sample and method.
Response: Thank you for your comment. The SDT has modified the standard to accommodate your comment. **The SDT has modified the Background Document to provide additional clarity as to how the thresholds were developed.**		
American Electric Power	No	It is unclear whether or not the guidance document will eventually become a part of the officially posted standard (in an appendix for example).
Response: Thank you for your comment. The Background Document will not be a part of the standard. The spreadsheet that the SDT has developed will be part of the standard.		
Texas Reliability Entity	No	The equations and methodology on CR Form 1 seem flawed. The recovery requirement in R1 is based on ACE, but the calculations in CR Form 1 are based on the MW lost. We believe the equations in CR Form 1 and the Background Document should be modified to incorporate the elements of the ACE equation into the calculations (i.e. frequency deviation and frequency bias in particular). For example, a recent unit trip of 1300 MW occurred. Based on the frequency deviation, the lowest ACE during the one-minute event period was -1900 MW. The language of the requirement and the CR Form 1 should reflect the recovery of the ACE (1900 MW) rather than the MW lost (1300 MW) in this case.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. The SDT discussed this relationship between frequency bias and ACE. In your example we believe the additional 600 MW of ACE deflection is due to the delta in your actual frequency response and the frequency bias in the ACE equation. As the MW's lost is replaced by deployment of contingency reserves, the frequency would return back toward 60 hz which would assist in returning ACE toward 0. The MW's lost is the amount of contingency reserves that need to be deployed to restore balance to the interconnection. The measurement of recovery from a loss is still best reflected in ACE.		
Keen Resources Ltd.	No	The definition of "Best ACE" is unclear as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. The purpose of this definition of "Best ACE" is to prevent R1's sanctioning a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce the BA's recovery requirement. By this definition of "Best ACE" a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording that I show in my Comment to Question 10, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period."
Response: Thank you for your comment. The SDT discussed your proposed method during the drafting of the standard but chose to not pursue this due to the complexities involved.		
Tucson Electric Power	Yes	very helpful

Organization	Yes or No	Question 9 Comment
Manitoba Hydro	Yes	No comment.

10. 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 the issue.

Summary Consideration: Several commenters disagreed with the use of 500 MW as a threshold for reporting a disturbance for all Interconnections. The SDT modified the threshold to use a value unique to each Interconnection.

Many commenters question why the SDT was not using the term Reportable Disturbance. The SDT explained that the term Disturbance as defined by the NERC Glossary of Terms is extremely broad and not specific. The term Balancing Contingency Event was defined to allow the SDT to be more specific as to what should be considered for purposes of this standard.

Some commenters were confused as to how to calculate a Reserve Sharing Group Reporting ACE. The SDT modified the definition to state that it was the algebraic sum of the BAs participating at the time of the event Reporting ACEs or equivalent.

A few commenters stated that BAAL would handle Balancing Contingency Events and therefore this standard was not necessary. The SDT explained that they agreed that BAAL would handle DCS within a 30 minute interval as it was voted on back in 2007. However, elimination of BAL-002 has not been supported by the industry in the past.

Several commenters believed that there should only be two requirements in the standard, recover from a reportable event and replenish reserves. The SDT explained that they had preserved the two requirements that were identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).

A couple of commenters wanted the SDT to use BAAL as the measure for performance in this standard. The SDT stated that they considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

Organization	Yes or No	Question 10 Comment
ACES Standards Collaborators		(1) We cannot support a 500 MW threshold for a Reportable Balancing Contingency

Organization	Yes or No	Question 10 Comment
		Event. The number is arbitrary without any technical justification. The background document explains how the drafting team reviewed CERTS data to arrive at the conclusion that a 100 MW threshold would cover all frequency events. Correctly, the drafting team determined that this was simply an unrealistic threshold and would not provide any additional reliability value. The background document then explains that the drafting team decided “to capture the majority of events having significant impact on frequency” by setting the threshold to 80% of the MSSC or 500 MW. It did not explain which value would do this or why it was important “to capture the majority of events”. Furthermore, there is no explanation why 500 MW is necessary when today 80% of MSSC is used. Has the use of 80% of MSSC resulted in an unreliable system? Thus, we can only conclude the value is arbitrary. Please remove the 500 MW value. (2) Additional justification is necessary to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, it is not consistent with BAL-005-0.2b which requires ACE calculation on at least a six second basis. A BA using a six-second sample rate could be viewed as being out of compliance if they used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any glitches in the data. What does an entity do if a scan was skipped or there was a data spike? More samples would make it less likely for this to be an issue. (3) The purpose needs to be modified. Please strike “balances resources and demand and”. The purpose of the standard is to recover ACE following a Reportable Balancing Contingency Event. The portion that needs to be struck is addressed by BAL-001. (4) The drafting team has an opportunity to assist NERC in moving the Reliability Assurance Initiative along and showing some of the first fruits of the initiative. One

Organization	Yes or No	Question 10 Comment
		of the key white papers written for the initiative focuses on the reducing the data requirements and retention periods necessary for the compliance and enforcement process. NERC compliance has a stated goal of reducing the data retention burden on registered entities. The data retention required for the current versions of this standard exceed what is necessary and this draft version perpetuates the problem. All BAs currently must submit monthly data to their regional entities for this standard which clearly shows whether they are compliant or not. Then they are still required to retain three years worth of data. Since the regional entities already have the data and know whether they are compliant or not, what reliability value does three years of data provide? None. The new version will only perpetuate this issue. In response to our previous comments, the drafting team indicated that the monthly reporting is not required by the standard and is up to the region. While this is true, it is highly unlikely that the regional entities will change this monthly reporting burden given that the standard is conceptually the same as the existing standard. Furthermore, the drafting team and NERC staff can review the issue with regional entity compliance personnel to confirm their plans for monthly reporting. If they do plan to continue with the monthly reporting, then no more than six months of data is necessary and we request that the standard should be changed. It will demonstrate a good faith effort on the part of NERC to move the RAI forward. (5) The data retention section is inconsistent with the 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. Since a BA is on a three-year audit cycle, the period from the previous audit will be about 3 years. It could be a little more or a little less. However, the data retention section of "the current year, plus three previous calendar years" (which could be up to four years) actually could exceed this three year audit cycle period. Consider if a BA completed their last audit on November 15, 2010. Their audit cycle would require another audit in 2013. Let's assume this is scheduled for December 15, 2013. This means the audit period is 3 years and 1 month. It also means per the Rules of Procedure that NERC

Organization	Yes or No	Question 10 Comment
		cannot review any period prior to November 15, 2010 for compliance unless there is an outstanding investigation. Per the data retention section, on December 15, 2013, the date of the audit, the BA would have to retain data for all of 2013 as well as all of the data for 2010, 2011 and 2012. By the Rules of Procedure, the auditors could not review any data prior to November 15, 2010. Thus, the registered entity would be compelled to retain for 11.5 months for which NERC is not allowed to review. How does this benefit reliability? The data retention period should be changed to retain data since the last audit. Changing the data retention period to be no longer than since the last audit would show a good faith effort in moving the RAI along. (6) The VSLs for Requirement R2 need to be justified. There is no explanation provided for the values chosen for the various thresholds. For example, the Lower VSL covers contingency deficiency for a period of 5 to 15 hours. Why shouldn't this go to 20, 30, 40 or any other number of hours? Without a justification, we can only assume the numbers were selected arbitrarily. We are also confused by the Lower VSL since it starts at 5 hours. Does this mean that a BA can be deficient of contingency reserves up to 5 hours without a violation occurring? (7) There is no explanation for why Reportable Disturbance is not a satisfactory definition as used in the existing standard and why it is replaced with Reportable Balancing Contingency Event. Furthermore, it is not proposed to be retired. If the term will no longer be used, it should be retired. (8) Thank you for the opportunity to comment.

Response: Thank you for your comment.

1) The SDT has modified the standard to provide individual interconnection reporting thresholds.
2) The change from 10 to 60 with 4 scans to the 16 seconds prior to event was meant to clarify the pre-event data and provide consistency with BAL-003-1. The SDT has modified the Background Document to provide additional clarity.
3) The Purpose Statement does reflect recovery of ACE since ACE recovery is intended to provide the necessary indication to assure the balancing of resource and demand.
4) & 5) The SDT does not have control over what the regions require for reporting. The SDT believes that your comment is outside

Organization	Yes or No	Question 10 Comment
the scope of the drafting team. 6) The SDT agrees that the selection of 5 hours could be considered arbitrary and is based on the judgment of the SDT. The SDT has modified the requirement and the Background Document to provide consistency and additional clarity. 7) The term Disturbance as defined by the NERC Glossary of Terms is extremely broad and not specific. The term Balancing Contingency Event was defined to allow the SDT to be more specific as to what should be considered for purposes of this standard. We have addressed the term Reportable by providing individual interconnection thresholds. The term Reportable Disturbance is presently used in other standards and therefore cannot be retired at this time.		
Texas Reliability Entity		1) In ERCOT, we have an existing process in place to analyze unit trips greater than 500MW. However, other interconnections may find it overly burdensome to analyze these unit trips based on their current size and loads. 2) R1, as stated, is an event-by-event obligation. A failure to recover for one event would constitute a violation, even though the Responsible Entity may have performed well for the remainder of the period. Is this the intent of the SDT? Would the SDT consider another measure, such as evaluation of multiple events on a quarterly basis? 3) Does the SDT intend to retire the existing “Disturbance Control Standard” definition? Do you need to modify definition of “Reserve Sharing Group” to not reflect usage of “Disturbance Control Performance”? 4) The Reserve Sharing Group Reporting ACE definition is different here than the Regulation Reserve Sharing Group Reporting ACE definition provided in BAL-001-2, which is correct? (i.e. Does not have “at the time of measurement” as last part of sentence). 5) How do you calculate a Reserve Sharing Group Pre-Reportable Contingency Event ACE Value? We assume it is the algebraic sum of the ACEs of the BAs that make up the Reserve Sharing Group, but it may need to be explicitly stated.
Response: Thank you for your comment. 1) The SDT has modified the standard to provide individual interconnection reporting thresholds.		

Organization	Yes or No	Question 10 Comment
2) Currently, in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base. 3) The SDT has modified the standard to eliminate the need to retire the existing Disturbance Control Standard definition or modify the definition for Reserve Sharing Group. 4) The SDT has made the necessary corrections. 5) The SDT has modified the definition for Reserve Sharing Group Reporting ACE to be the algebraic sum of the Reporting ACEs or equivalent.		
Modesto Irrigation District		A technical justification for the "16 second interval" for ACE and the "105 minutes" value for Contingency Reserve demonstration needs to be added.
Response: Thank you for your comment. The background document has been modified to include a discussion on the 16 second interval. The 105 minutes is the current time for DCS and comes from the 15 minutes of the event and the 90 recovery period.		
Duke Energy		o As the BAAL proposed in BAL-001-2 will address the loss of any resource, or any other change in ACE causing a Balancing Authority to exceed its BAAL, it could be argued that there is no reliability need to retain DCS. In 2007, the NERC Operating Committee supported the adoption of the BAAL and a subsequent field trial of operating without DCS to determine if the Standard was still needed. Until more experience is gained under the BAAL, Duke Energy supports having a Standard driving a Balancing Authority to address the largest of its events as it does today, however we see no reliability need to expand BAL-002 beyond the simple concept of measuring the recovery to the largest of the BA’s resource losses - 80% or greater of the MSSC, and limited to MSSC, where the applicable events are clearly understood by the operator. Duke Energy disagrees with applying compliance and associated compliance reporting on an event-by-event basis, rather than allowing the quarterly reporting currently provided under BAL-002. The measures for compliance should recognize that no technical basis has been provided to support the 15-minute recovery required under Requirement R1 - compliance to a line drawn in the sand can be measured on a quarterly basis similar to today, as real-time reliability needs will

Organization	Yes or No	Question 10 Comment
		be met by the BA being held to compliance under BAAL. o Duke Energy disagrees with the definition of "Reportable Balancing Contingency Event". Given that all resource losses will be captured by the BAAL under BAL-001-2, that there is no basis for using 500 MW as a baseline for reporting, and that there has not been a demonstrated reliability need to move away from our current reporting criteria of 80% or greater of the MSSC, Duke Energy does not support the inclusion of the 500 MW threshold in the definition.. We believe that BAAL 30-minute response covers all events, and DCS action is a 15-minute response intended to address large events. We agree with MISO's comment that currently DCS is measured quarterly, and the proposed Requirement R1 creates an unnecessary event-by-event compliance evaluation. Adding the 500 MW threshold and multi-contingent event expectation is excessive, with no benefit to reliability. o Duke Energy believes that Reserve Sharing Group should have the flexibility to calculate a group ACE rather than just taking the algebraic sum of all the BA ACEs.
Response: The BARC SDT acknowledges that BAAL would handle DCS within a 30 minute interval as it was voted on back in 2007. However, elimination of BAL-002 has not been supported by the industry in the past. In addition, currently in all NERC/FERC investigations of events involving DCS compliance, they have applied compliance and associated penalties on an event by event base. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **The SDT has modified the definition for Reserve Sharing Group Reporting ACE to be the algebraic sum of the Reporting ACEs or equivalent.**		
Manitoba Hydro		Although Manitoba Hydro is in support of this standard, we have the following clarifying comments: (1) Definitions, Reportable Balancing Contingency Event - there is no definition within the standard or Glossary as to what 'EMS scan rate data' is.

Organization	Yes or No	Question 10 Comment
		(2) Definitions, Contingency Event Recovery Period - the definition does not clearly define exactly when the Contingency Event Recovery Period begins. As written, the definition seems to indicate that this period begins at two different times (i) when the resource output begins to decline and (ii) in the first one minute interval of a Balancing Contingency Event. Please clarify. (3) 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? (4) 1. (Proposed) Effective Date in both Standard and Implementation Plan - remove the " ' " following the word 'Trustees' because it is not defined this way in the Glossary of Terms. (5) R1 - as written, R1 requires that the Responsible Entity demonstrate that ACE was returned to a certain value. The demonstrate aspect of the requirement seems more of a measure than a requirement. In other words, the requirement should be that the Responsible Entity return the ACE to a certain value, the measure is that they provide evidence to demonstrate that they did so. (6) R1, R2 - both 'MSSC' and 'Most Severe Single Contingency (MSSC)' are used throughout the standard. The words 'Most Severe Single Contingency (MSSC)' should be used at the first instance and then the acronym 'MSSC' for all instances thereafter. (7) R2 - some of the terminology appears to be incorrect within this requirement. Is 'Disturbance Recovery Period' meant to be 'Contingency Event Recovery Period'? Is 'Contingency Reserve Recovery Period' meant to be 'Contingency Reserve Restoration Period'? (8) M1 - the word 'including' should be replaced with 'as well as' if the 'additional documentation' that needs to be provided is in addition to the CR Form 1, not that the additional documentation forms part of the CR Form 1. (9) VRF/VSL - capitalize 'bulk electric system' in both the High Risk Requirement and

Organization	Yes or No	Question 10 Comment
		Medium Risk Requirement sections. (10) VSL, R1 - the language of the VSL does not track the language of the requirement or measure. The VSL refers to 'recovering from an event' while the requirement refers to returning ACE to a certain level. (11) VSL, R2 - the language of the VSL does not track the language of the requirement or measure. The VSL refers to calendar quarters, while the requirement and measure do not.

Response: Thank you for your comment.

1 – The SDT understands that the phrase "EMS scan rate data" is used in several other standards (i.e., BAL-005 and BAL-003-1) and is a commonly used term within the industry.

2 – The definition, as presently written, is very clear and is intended to be read as written. The Contingency Event Recovery Period begins at the time specified and is to be read as one entire clause which is why it is not otherwise punctuated. In other words, the phrasing should not be broken into two parts.

3 – The language that is being used in this draft of the standard is the latest NERC approved language for Compliance Enforcement Authority.

4 - The language that is being used in this draft of the standard is the latest NERC approved language for Effective Date.

5 – The SDT agrees with your comment and has made the necessary modifications.

6 – The SDT spelled the phrase out for clarity and emphasis.

7 – The SDT realized that the incorrect terms had been used in this posting. This has been corrected.

8 – The SDT has modified the measure to provide additional clarity.

9 – The SDT has corrected the error that you have identified.

10 – Recovery from an event is returning your ACE to the conditions defined in Requirement R1. Therefore, recovery is incorporated into satisfying R1.

11 – The SDT has modified the language used in Requirement R2.

Organization	Yes or No	Question 10 Comment
Florida Municipal Power Agency		BAL-002, R1 states that the Responsible Entity shall demonstrate that it returned its ACE to zero (less some modifiers); in other words, the standard requires ACE to be returned to an absolute number, without a tolerance. I believe this is not the intent of the SDT, that they probably meant zero or positive, or something like that; but, reading the requirement literally, I believe it would be difficult to prove compliance using integrated values for ACE that will likely not equal zero.
Response: Thank you for your comment. The SDT has modified the language in Requirement R1 to address your concern.		
MRO NERC Standards Review Forum		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives. Recommend that each interconnection has a different MW level, due to the sheer size of each interconnection. As an Eastern Interconnection entity, we recommend 900 MW vise 500 MWs. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. Our recommendations are: Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes).

Organization	Yes or No	Question 10 Comment
		Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. o Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. o The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority. The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. To remedy this deficiency in the proposed

Organization	Yes or No	Question 10 Comment
		standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by the NSRF, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. The NSRF is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.
Response: Thank for your comments. **1. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **2. The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).** **3. This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry.** **4. The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL).** **5. The SDT is developing a Reserve Guideline for approval and posting by the NERC OC.** **6. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **7. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
MISO Standards Collaborators		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL are crafted, this is now

Organization	Yes or No	Question 10 Comment
		an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North America compared to what existed under Policy 1. The changes being implemented are well beyond what was in the drafting team's SAR and the Order No. 693 directives.The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves within 90 minutes. These should be the basis of BAL-002-1. A Contingency Reserve Policy Guideline document in conjunction with the recommendations below should be sufficient to meet the drafting team SARs and the directives: o Preserve the two true requirements today (recover from reportable events within 15 minutes and replenish reserves in 90 minutes). o Provide clarity in the compliance section of the standard or the background document how events > MSSC are reported. Note: We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. o Due to concerns we have in BAL-013, we believe the reporting form for BAL-002 should also have a reporting slot for large loss of load events (Order No. 693 directive), but for reasons we state in BAL-013, believe that these should be excluded from compliance evaluation. Also BAL-001's RBC is a more effective way to meet the FERC directive for loss of load events. o The continent-wide contingency reserve policy should be a separate guidance document under the purview of the NERC Operating Committee with comments collected under the standards process along with this standard. This meets the 693 directive. The policy document should provide guidance on how the BA should assess the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the policy, NERC should add these four types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation in the policy that

Organization	Yes or No	Question 10 Comment
		Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and relay this to their RC. The policy would be available for re-review if the BA's performance approaches non-compliance. o The standard should be based on the lesser of 80% of MSSC, 1000MW, or a lower value chosen by the Balancing Authority.
Response: Thank for your comments. **1. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **2. The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).** **3. This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry.** **4. The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL).** **5. The SDT is developing a Reserve Guideline for approval and posting by the NERC OC.** **6. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
IRC-SRC		Besides the concerns presented above, we are troubled with the significant changes that will occur within R1 compared to today's DCS and the fact that the drafting team is asking no questions about those changes. The current DCS is measured on a quarterly basis. The way the proposed requirement 1 and VSL is crafted, this is now an event by event compliance evaluation. When you add the fact that the team is also embedding a 500 MW reporting threshold and the multi-contingent event expectation, this exposes the industry to a heavy-handed standard for no reliability need. It should be noted that DCS performance has been stellar across North

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<table>
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2. The SDT has preserved the two requirements that you have identified within Requirement R1 and R2. In addition, the proposed Requirement R2 preserves the existing requirement to maintain reserve equal to MSSC (present Requirement R3.1).
3. This standard is designed to measure performance of your contingency reserve for Balancing Contingency Events up to your MSSC. This does not relieve you from meeting all of the other NERC reliability standards during these events. While the SDT understands your concern about single contingencies greater than MSSC, the SDT has chosen to use a single pre-determined contingency as the basis for this standard since it is well defined within the industry.
4. The SDT agrees with the industry with regards to the need for BAL-013-1. The SDT has chosen to stop development on a Large Loss of Load standard (BAL-013-1) and believes that the loss of a large load is covered in BAL-001-2 Requirement R2 (BAAL).
5. The SDT is developing a Reserve Guideline for approval and posting by the NERC OC.
6. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.</td></tr>
<tr><td>Bonneville Power Administration</td><td></td><td>BPA is in support of this standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your support.</td></tr>
<tr><td>ERCOT</td><td></td><td>ERCOT ISO supports the intention of the standard BAL-002-2 R1 to restore ACE back to pre-disturbance ACE but not necessarily to zero or the pre-disturbance ACE. The ACE recovery goal should be pre-disturbance levels. Therefore, ERCOT suggests the SDT establish a (epsilon1*Frequency Bias*10) band around the pre-disturbance ACE or zero ACE, and, if during recovery ACE is recovered within this range, entities would be compliant. This structure of establishing a goal, but providing for a compliance "floor" based upon the proposed range, will achieve the desired reliability benefits while also providing a reasonable degree of flexibility for circumstances where recovery to the exact pre-disturbance level is difficult to achieve, and unnecessary to</td></tr>
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Organization	Yes or No	Question 10 Comment
		ensure reliability. ERCOT ISO also suggests that the 500 MW threshold be removed from the definition of Reportable Balancing Contingency Event. This requirement would impose an undue burden. There is no reliability reason to require mandatory reporting for these smaller events. It will merely create an administrative obligation with no corresponding reliability benefits. For instance, currently ERCOT ISO would typically need to report less than five events annually, but this new standard would increase this reporting burden to over 50 each year (based upon 2012 disturbances), without any corresponding reliability benefits. Accordingly, this obligation should be removed.If the SDT elects not to remove the 500 MW threshold generally, ERCOT ISO suggests that the threshold be removed for single-BA Interconnections. The threshold for single-BA Interconnections should be established as 80 percent of the MSSC. ERCOT ISO is voting "yes", but has reservations as described above and requests that the SDT revise the standard accordingly.
Response: Thank you for your comment. **In response to your concern, the SDT has modified Requirement R1.** **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.**		
NextEra Energy		Have the option also calculate ACE using the following formula: ACE = (NIA â ˆ’ NIS) â ˆ’ 10B (FA â ˆ’ FS) - IME
Response: Thank you for your comment. In response to your concern, the SDT has modified the definition.		
Avista		I can support this draft standard with the clarifications requested in Question #1 above.

Organization	Yes or No	Question 10 Comment
Response: Thanks you for your support. Please refer to our response to your comments for Question #1.		
American Electric Power		In addition to the comments provided to the earlier questions above, AEP offers the following additional comments for consideration. AEP disagrees with the latest proposed definition of “Preâ€Reportable Contingency Event ACE Value”, which has been made ambiguous by the most recent modifications. What is the intent of the drafting team in modifying the definition in this way? If this definition were to be used, new tools would likely need to be developed in order to calculate the value in this manner, as the operators would now be required to continuously calculate the ACE value based on this new definition. The definition for, and application of, Contingency Event Recovery Period is unnecessarily complex, confusing, and likely unpractical in its application. For example, if a unit was taken out of service due to a controlled shut-down, the Real Time Operator’s most pressing responsibility is balancing load and generation. Requiring this person to use the proposed methodology to determine exactly the contingency event recovery period began would distract the Real Time Operator from their core balancing responsibilities. Rather than take this approach, we recommend retaining the existing way of determining when the recovery period begins, which is a more straightforward and reasonable approach. In addition, the definitions for Contingency Event Recovery Period and Contingency Reserve Restoration Period are quite similar and would most likely prove confusing to industry in their application. Taking a conditional-based approach across multiple standards does not serve the reliability of the bulk electric system, as it takes a straightforward concept, overly complicates it, and distracts Real Time Operators from the core reliability objectives.
Response: Thank you for your comment. **1 & 2 - The SDT had no intent of causing you to change how you determine your ACE today under the existing standard, however,**		

Organization	Yes or No	Question 10 Comment
they intended to provide the necessary flexibility for you to account for prior and subsequent Balancing Contingency Events during the defined period. In addition, the determination of the pre-contingent ACE was modified to be consistent with the direction of BAL-003-1 and to eliminate possible inconsistency in its determination. **3 – The SDT created the definitions to provide additional clarity and flexibility for the BAs.** **4 – The SDT does not understand your comment about "conditional based approach across multiple standards" and therefore would need additional information to provide a response.**		
PJM Interconnection, LLC		In R1 and R2, delete the language related to a Responsible Entity under an Energy Emergency Alert Level 2 or Level 3, for the following reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE - this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection - wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. PJM appreciates the SDT's goal of drafting a continent-wide standard but disagrees with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, PJM believes that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500MW as an example, a loss of 500MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. PJM believes that this SDT

Organization	Yes or No	Question 10 Comment
		and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared annually by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection (ALR1-12 Assessment). As previously stated, PJM respectfully suggests that the SDT give due consideration to redefining a Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. PJM believes this is one approach that could satisfy the directive set forth in Order 693.
Response: Thank you for your comment. **1 – The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **2 & 4 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **3- The SDT has modified the definition for Reporting Ace addressing your concern.**		
Portland General Electric Company		Portland General Eletric is supportive of this standard.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your support.		
Seminole Electric Cooperative, Inc.		Provide flexibility for an RSG ACE to be calculated based on aggregate participants frequency bias and RSG interchange with non-participants.
Response: Thank you for your comment. The SDT has modified the definition to address your comment.		
ReliabilityFirst		ReliabilityFirst votes in the negative for this standards and offers the following for consideration: 1. Definition of Reportable Balancing Contingency Event: ReliabilityFirst does not agree with the inclusion of last sentence (i.e., The 80% threshold may be reduced upon written notification to the Regional Entity) within the definition. As written, the definition infers that there is an expectation that a Regional Entity may have to make a determination on whether to accept a reduction in the 80% threshold based upon the written notification. This is troublesome in two ways. One, this is written more like a requirement, though it is actually contained within a definition. Two, standards should not be written with expectation placed upon a non-registered entity (i.e., the Regional Entity). ReliabilityFirst recommends removing this last sentence and any reference to the Regional Entity. 2. Applicability Section - ReliabilityFirst recommends removing the paragraph stating “Applicability is determined on an individual event basis...” from the Applicability section. The Applicability section should state the functional entity that is required to comply with the standard and the requirements should state any conditions necessary to achieve the action or outcome.
Response: Thank you for your comment. **1 – The definition does not put a requirement on the Regional Entity. The definition simply requires the Regional Entity to be notified.** **2 – The individual event basis was included to allow for the flexibility for individual BAs participating in a Reserve Sharing Group**		

Organization	Yes or No	Question 10 Comment
but opting out of the group for an individual event basis in accordance with the respective Reserve Sharing Group agreement.		
Oklahoma Gas & Electric		Remove the 500 MW threshold in the definition of Reportable Balancing Contingency Event
Response: Thank you for your comment. The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.		
seattle city light		Seattle City Light supports the general concepts of this draft of BAL-002-2, but as with BAL-001-2, Seattle thinks this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Several specific recommendations for changes have been noted above. However, at least until the Guidelines document is available that details how this Standard will work in conjunction with other BAL Standards, Seattle cannot support this draft.
Response: Thank you for your comment. The SDT is presently working on the Reserve Policy Guideline document. The SDT will be presenting the draft Guideline document to the NERC OC for their acceptance at their September 2013 meeting.		
Tacoma Power		Tacoma Power appreciates the opportunity to provide comments. We cannot support this draft of the standard because we are unfamiliar with the phrase, "... known load used as a resource ..." in the definition of a Balancing Contingency Event. Therefore, this phrase must be defined or replaced so that there is no confusion within the industry and compliance authorities. We suggest using the phrase, "... interruptible load claimed as available reserves ...," which is Tacoma Power's interpretation. In addition, the VSLs are very confusing. All levels state that the Responsible Entity recovered from the event, yet they recovered to less than 100% of the required recovery. How can it be "recovered" without reaching 100%? Instead, we suggest that the VSLs recognize that the Responsible Entity "partially recovered" from the event.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comment. **The SDT has modified the definition to address concerns from the industry.** **The SDT has modified the VSLs for Requirement R1 based on comments from the industry.**		
Energy Mark, Inc.		The definition of "Pre-reportable Contingency Event ACE Value" should be modified as follows:The term "ACE" should be replaced by the term "Reportable ACE" wherever it is used in this definition. "ACE" is not adequately defined while "Reportable ACE" is. I would strongly suggest that the wording for Requirement 1 should be modified to read as follows:R1. Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, the ResponsibleEntity experiencing a Reportable Balancing Contingency Event shall demonstrate thatwithin the Contingency Event Recovery Period the Responsible Entity returned its Reportable ACEto: [Violation Risk Factor: Medium][Time Horizon: Realâ€?time Operations]ï,· Zero, (if its Preâ€?Reportable Contingency Event ACE Value was positive or equal tozero):o less the sum of the magnitudes of all subsequent Balancing ContingencyEvents that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, ando Further reduced by the magnitude of the difference between (i) theResponsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sumof the magnitudes of the Reportable Balancing Contingency Event and allprevious Balancing Contingency Events that have not completed theirContingency Event Restoration Period when the sum referenced in clause (ii)of this bullet is greater than MSSC,Or,ï,· Its Preâ€?Reportable Contingency Event ACE Value, (if its Preâ€?ReportableContingency Event ACE Value was negative),o less the sum of the magnitudes of all subsequent Balancing ContingencyEvents that occur prior to that value of Reportable ACE within the Contingency Event Recovery Period, ando Further reduced by the magnitude of the difference between (i) theResponsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sumof the magnitudes of the Reportable Balancing Contingency Event and allprevious Balancing Contingency Events that have not completed

Organization	Yes or No	Question 10 Comment
		theirContingency Event Restoration Period when the sum referenced in clause (ii)of this bullet is greater than MSSC.
Response: Thank you for your comment. **The SDT has modified the definition of Reporting ACE based on comments from the industry.** **The SDT has modified Requirement R1 to address your comment.**		
Xcel Energy		The drafting team is proposing to continue to use only ACE under Requirement R1 as the measure of reliability in the determination of Balancing Authority or RSG compliance. As has been seen in actual operation, the current methodology can lead to and has caused RC directives to drop load when there was not a reliability issue, defined as a frequency concern or transmission line loading issue. ACE is not a primary measure of reliability, only equity. Therefore, Xcel Energy is voting against the proposed standard. To remedy this deficiency in the proposed standard, the drafting team should utilize the BAAL limit as a more appropriate measure of response to the sudden loss of generation, not pre-event ACE or zero, whichever is lower. As proposed by Xcel Energy, this does not do away with DCS as originally proposed under BAAL but would change the measure of compliance in the DCS process to a more appropriate, reliability based measure. Xcel Energy is also not proposing to change the 15-minute period in BAL-002 for a reportable event with this modification.
Response: Thank you for your comment. The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve. The issue you have raised is outside the scope of this standard and should be resolved when IRO-005-4 is approved by FERC.		
PPL NERC Registered Affiliates		The PPL NERC Registered Affiliates offer the following comments: With respect to the proposed definitions, it is not clear why the SDT modified each of the proposed definitions but is only requesting input on a subset of the defined terms

Organization	Yes or No	Question 10 Comment
		during this comment period. With respect to requirement 1, it is suggested that the phrase "Except when an Energy Emergency Alert Level 2 or Level 3 is in effect," be deleted for the following reasons: 1) An EEA in effect for any BA or RSG other than the responsible entity experiencing the contingency should not give the responsible entity an exemption from R1. For example, an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent responsible entity anywhere in the eastern interconnection. The language makes the assumption that both the EEA and contingency are affecting a single, specific responsible entity - if this is what the SDT intended, the language as currently written is too generic. 2) The Applicability section clearly states that the standard does not apply to a responsible entity under an EEA. If the SDT intends to include the exemption in the requirement language, it is suggest R1 is revised as follows: "Except when an Energy Emergency Alert Level 2 or Level 3 has been requested by the Responsible Entity, the Responsible Entity experiencing a Reportable ..." . Also, we suggest it would be more appropriate for the Responsible Entity to restore ACE to within the BAAL limits rather than the "hard" zero or pre-contingent ACE value within the 15 minute recovery period. Once a responsible entity has restored ACE within the BAAL limits it is no longer burdening the interconnection - this would be a sufficient recovery.We suggest that a successful response by the responsible entity would return ACE to the lesser of 0 or its real time BAAL limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly - ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL limit (if its Pre-Reportable Contingency Event ACE was negative). With respect to R2, it is not clear if responsible entity experiencing a non-reportable Balancing Contingency Event (i.e. a loss less than 500MW) is expected to maintain

Organization	Yes or No	Question 10 Comment
		Contingency Reserves at least equal to its MSSC. As currently written, it appears that R2 could require a Responsible Entity to always carry Contingency Reserves equal or greater than its MSSC plus 500MW (or its reportable threshold) so that Contingency Reserves will always exceed MSSC. With respect to measurement M2, it is not clear if Contingency Reserves may fall below MSSC for the first 105 minutes (Contingency Event Recovery Period plus Contingency Reserve Restoration Period) following any deployment of Contingency Reserves. If so, this may resolve the current expectation as written in R2. However, measures are not requirements and therefore, compliance is not judged through any potential flexibility provided in M2 or the VSLs. Requirement 2 (along with the currently effective version 1 of BAL-002) uses a capitalized term “Disturbance Recovery Period” that is not in the NERC Glossary of Terms. The SDT may have intended to use the term Contingency Event Recovery Period in lieu of Disturbance Recovery Period in requirement 2.

Response: Thank you for your comment.

1 – The SDT only asked questions when it made a significant modification. The SDT was not precluding anyone from providing a comment on any part of the standard through Question #10.

2 – The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.

3 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.

4 – The SDT has modified Requirement R2 in response to concerns raised by the industry.
5 – An entity may deploy contingency reserve for any Balancing Contingency Event whether the event is reportable or not which provides you 105 minutes to restore your reserve.

6 – The SDT has made the necessary correction for the error you identified.

Organization	Yes or No	Question 10 Comment
NV Energy		The Reportable Balancing Contingency Event definition lacks clarity. Are we to choose the higher of 500 MW vs. 80% of the MSSC or the lower of 500 MW vs. 80% of the MSSC? Seems like the measurement should be the higher of the two. 2. While I think I understand the goal of R1, to return ACE to zero neglecting other contingency events within the recovery period, the wording is very confusing. Expect misapplication of the standard with the existing wording. I suggest, for bullet #2: o Its Preâ€Reportable Contingency Event ACE, (if its Preâ€Reportable Contingency Event ACE was negative), o less the Balancing Contingency Events' magnitude summation for all subsequent events occurring within the Contingency Event Recovery Period, and o If the contingency event is greater than MSSC, further reduce the ACE recovery magnitude by difference between the Responsible Entity's MSSC and the uncompleted Balancing Contingency Events' magnitude summation.
Response: Thank you for your comment. **The reporting threshold would be the lower of either 80% of MSSC or the interconnection threshold.** **The individual event basis was included to allow for the flexibility for individual BAs participating in a Reserve Sharing Group but opting out of the group for an individual event basis in accordance with the respective Reserve Sharing Group agreement.**		
Keen Resources Ltd.		The wording of the recovery target ACE in Requirement 1 needs to be replaced as follows: "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur WITHIN THE CONTINGENCY EVENT RECOVERY PERIOD [caps mine]" should be replaced by "less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur AT THE MOMENT OF RECOVERY (OR NEAREST-RECOVERY), or beforehand [caps mine]". Otherwise, by containing the word "all" in the selected wording, R1 sanctions a BA's avoiding non-compliance due to insufficient reserve, by incurring a subsequent contingency within the recovery period to reduce

Organization	Yes or No	Question 10 Comment
		the BA's recovery requirement. Furthermore, the current R1 definition contradicts the definition of "Best ACE" contained in the Background Document that was intended to preempt such BA behavior by defining "Best ACE" as: the "most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)". The meaning of "if any" is specified only in the attached spreadsheet that makes "claiming" such a subsequent event "optional" to the BA. In other words, a BA will not claim a subsequent event that makes the BA's compliance worse. A clearer alternative definition of "Best ACE", that does not require the "optionality" obscurely lodged in the spreadsheet and that would harmonize with the needed change to the R1 wording, would be "the least negative value if there are no positive values, or the most positive value of any positive values, among the values of ACE occurring during the recovery period, unless it is the ACE to which the addition of any subsequent events that occurred prior to or concurrently with it results in a value that is the least negative value if there are no positive values, or the most positive value of any positive values, among all such resultant values and the other ACE values during the recovery period."
Response: Thank you for your comment. **The SDT understands your concern and has made modifications to Requirement R1 based on comments from the industry.** **The SDT discussed your proposed method during the drafting of the standard but chose to not pursue this due to the complexities involved.**		
SERC OC Standards Review Group		There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported, but not evaluated for compliance. While it's

Organization	Yes or No	Question 10 Comment
		fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all Interconnections. In the proposed BAL-001-2, the BARC SDT proposes a definition of ACE that is only applicable for the Western Interconnection. In BAL-003-1, that was recently approved by the industry and the NERC BOT, the FR SDT identified different frequency excursion criteria for each Interconnection that are used to identify candidate events for evaluating frequency response performance. The FRI Report, approved by the NERC PC and accepted by the NERC OC, identified different statistically derived delta frequencies for each Interconnection in developing IFRO's. The State of Reliability Report prepared by the NERC identifies "the triggers for significant frequency events" that are specific to each Interconnection.We respectfully suggest that the SDT give due consideration to redefining a Balancing Contingency Event and Reportable Balancing Contingency Event that satisfies the Commission directive of defining a significant (frequency) deviation. Such a definition could resemble 80% of MSSC or a supply, load, or scheduling event that results in a frequency deviation of XXmHz (depending on the Interconnection) in any rolling XX second period. Previous work completed by the FR SDT and NERC staff could be leveraged to this end. We believe this is one approach that could satisfy the directive set forth in Order 693. In R1 and R2, delete the language related to an RE under an Energy Emergency Alert

Organization	Yes or No	Question 10 Comment
		Level 2 or Level 3, for 2 reasons: (1) An EEA in effect for any BA or RSG other than the RE experiencing the contingency should not give the RE an exemption from R1. E.g. an EEA in effect for a BA in Florida should not be a consideration for the performance of a contingent RE anywhere in the EI. The language makes the assumption that both the EEA and contingency are affecting a single, specific RE - this is probably what the SDT intended but the language used in R1 and R2 is too generic. (2) The "Applicability" section clearly states that the standard does not apply to an RE under an EEA. Words could be added to R1 and R2 to clarify that the contingent RE is also the RE experiencing an EEA but a better solution is to simply delete the EEA related language from R1 and R2, Would it be sufficient for the RE to restore ACE to within the dynamic BAAL limits instead of the "hard" criteria of zero or pre-contingent ACE value within the 15 minute recovery period? Once an RE has gotten ACE within the BAAL limit it is no longer burdening the interconnection - wouldn't this be a sufficient recovery? There should be coordination of the recovery required under BAL-002 with performance under the BAL-001(BAAL) standard. We suggest that a successful response by the RE would return ACE to the lesser of 0 or its real time BAAL low limit (if its Pre-Reportable Contingency Event ACE was positive or equal to zero) and similarly - ACE returned to the lesser of its Pre-Reportable Contingency ACE Value or BAAL low limit (if its Pre-Reportable Contingency Event ACE was negative). If the interconnection frequency is high - why require a BA to increase generation more than is necessary to meet its BAAL low limit? If interconnection frequency is low, the BAAL low limit as well as the zero or pre-contingent ACE rule would still apply. These comments were also supporteed 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

Organization	Yes or No	Question 10 Comment
		as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you for your comment. **1 – The SDT modified the existing standard by eliminating administrative requirements, however. they have maintained requirements associated with performance and addressed the FERC directive in order 693.** **2 & 3 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **4 - The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **5 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
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		There is an embedded expectation to recover from and measure multi-contingent events beyond MSSC. When these events happen, something bigger is going on. Transmission security is probably an issue. Forcing a knee-jerk expectation to drive ACE back toward zero during a major event will likely do more harm than good. This is another thing that wasn't in the drafting team's SAR or in a directive. Events greater than MSSC should be reported but not evaluated for compliance. While it's fine to embed some of the calculations in the background document in a reporting form, events greater than MSSC should be excluded from compliance evaluation. We appreciate the SDT's goal of drafting a continent-wide standard but disagree with the SDT's approach of 'one size fits all' in defining a Reportable Balancing Contingency Event. As previously stated, we believe that the Commission directive of defining a significant (frequency) event is not satisfied by this standard. Additionally, using 500 MW as an example, a loss of 500 MW may cause a significant frequency deviation at midnight on April 1st but not at 17:00 on August 1st. The same 500 MW loss may cause a significant frequency deviation in the Western Interconnection but not in the Eastern Interconnection. We believe that this SDT and other SDT's have acknowledged that a 'one size fits all' approach is not always appropriate for all

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Response: : Thank you for your comment. **1 – The SDT modified the existing standard by eliminating administrative requirements however we have maintained requirements associated with performance and addressed the FERC directive in order 693.** **2 & 3 – The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis.** **4 - The SDT understands your concern and has modified Requirement R1 and Requirement R2 accordingly.** **5 - The SDT considered using the approach of BAAL as the basis for performance but chose the present method since concerns other than frequency performance may need to be addressed. There is also a compelling interest in measuring the adequacy of reserve.**		
Northeast Power Coodinating Council		There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability. The Standard can be simplified by replacing the existing requirements with ones that read: o recover from a Reportable Event within 15 minutes; o replenish reserves within 90 minutes.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comment. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis. In addition, the SDT is attempting to respond to the FERC directive to identify those events that can have a significant impact on frequency.** **At the core Requirement R1 does require recovery in 15 minutes. The additional qualifications allow for flexibility to address unusual circumstance that can arise.** **Requirement R2 provides for recovery of reserves within 90 minutes. The additional qualifications allow for flexibility to address unusual circumstances that can arise.**		
ISO New England Inc.		There isn't an appropriate technical justification for requiring a 500 MW threshold. If the justification is simply to obtain more data samples, a 1600 data request is more appropriate than an enforceable Standard. Suggest reverting back to the 80% threshold which has thus far, shown to provide for an adequate level of reliability.The Standard can be simplified by replacing the existing requirements with ones that read: o recover from a Reportable Event within 15 minutes; o replenish reserves within 90 minutes.As written, the Standard is overly complex.
Response: Thank you for your comment. **The BARC SDT has modified the standard to provide for the reporting threshold to be on an Interconnection by Interconnection basis. In addition, the SDT is attempting to respond to the FERC directive to identify those events that can have a significant impact on frequency.** **At the core Requirement R1 does require recovery in 15 minutes. The additional qualifications allow for flexibility to address unusual circumstance that can arise.** **Requirement R2 provides for recovery of reserves within 90 minutes. The additional qualifications allow for flexibility to address unusual circumstances that can arise.**		
Independent Electricity System Operator		We will support this standard, however please note the concerns expressed under Q2 and Q3, above, namely:

Organization	Yes or No	Question 10 Comment
		a. The last sentence in the definition for Contingency Reserve, and b. The need to define the term Reserve Sharing Group Reporting ACE (or the lack of explicit requirement for RSG to meet the DCS requirement).
Response: Thank you for your comment and support. Please refer to our response to your comments on Questions 2 and 3.		
Exelon		While we appreciate the work done since previous versions of the project, and recognize the clarity gained by eliminating reference to Balancing Contingency Events with a future impact to ACE, we feel that additional confusion has been inserted by the sub-points of R1. Given that the recovery requirement is a relatively short time-frame, the ability to quickly determine the recovery obligation is critical to the ability to ensure compliance. We appreciate that the drafting team is attempting to accommodate the notion that a prior Balancing Contingency Event might impact any future events, but the methodology given for determining the recovery threshold is overly complex, and represents a significant barrier to a system operator's ability to interpret the requirement in Real Time and respond appropriately.
Response: Thank you for your comment. The present BAL-002 has 16 requirements and sub-requirements. The SDT has reduced this down to two requirements, recover from a reportable event and ensure you have reserves.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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.

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, 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

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Suite 600, North Tower

Atlanta, GA 30326

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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

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # 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	

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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	

Non-binding Poll Results

Project 2010-14.1 BAL-002-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-14.1 BARC BAL-002-2 Non-binding Poll
Poll Period:	4/16/2013 - 4/25/2013
Total # Votes:	281
Total Ballot Pool:	325
Summary Results:	86.46% of those who registered to participate provided an opinion or an abstention; 43.96% 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	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	
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	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
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	Negative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
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	Negative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	
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	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
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	Negative	
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	Negative	

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	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
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	Negative	
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
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	Negative	
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	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	

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3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
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	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
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	Abstain	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
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	Affirmative	
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	Negative	
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	Consumers Energy Company	Tracy Goble	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
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		
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	Negative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
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	Negative	
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	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Abstain	
5	Colorado Springs Utilities	Michael Shultz	Affirmative	
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	Negative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	

5	Gainesville Regional Utilities	Karen C Alford	Abstain	
5	Great River Energy	Preston L Walsh	Negative	
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	Negative	
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	Negative	
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	Abstain	
5	Platte River Power Authority	Roland Thiel	Negative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
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	Negative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Abstain	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
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	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		

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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	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
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	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	
6	Duke Energy	Greg Cecil	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
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	Negative	
6	Omaha Public Power District	Douglas Collins	Negative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	
6	Portland General Electric Co.	Ty Bettis	Affirmative	
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
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	Negative	
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	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	

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	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Robert Blohm	Negative	
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	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for a 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 10-day re-circulation ballot from July XX, 2013 through July XX, 2013.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation Ballot	July 2013
2. NERC BOT adoption.	August 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.

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.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$ 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 * 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:

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

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 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}):

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

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

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**:**

$BAAL_{Low}$ 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:

- 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.

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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for a 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed new standard. This proposed draft standard will be posted for a 10-day re-circulation ballot from July XX, 2013 through July XX, 2013.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Recirculation Ballot	July 2013
2. NERC BOT adoption.	August 2013

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~~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 (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 N~~n~~et A~~a~~ctual Interchange and its Net S~~s~~cheduled I~~I~~nterchange, 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)~~. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

Reporting ACE is calculated as follows:

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

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

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- $Y = B / B_S$.
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  Where:

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

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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.

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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.

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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.

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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.

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

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**:**

$BAAL_{Low}$ 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:

- 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.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$ 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 * 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 Rreserve required for all member Balancing Authorities to use in meeting applicable regulating standards.

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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 N~~n~~et A~~a~~ctual Interchange and its Net S~~s~~cheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC).

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$$I_{ATEC} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}$$ 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 $(1-Y) * (II_{actual} - B * \Delta TE/6)$
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  $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$

- 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:

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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:

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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

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

July 2013

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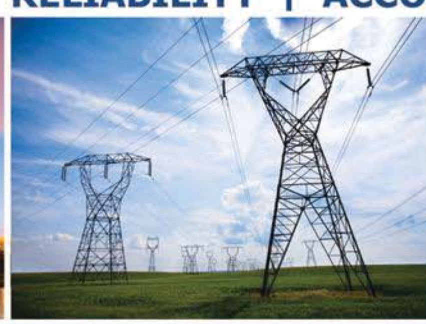


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Introduction

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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.

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- 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.

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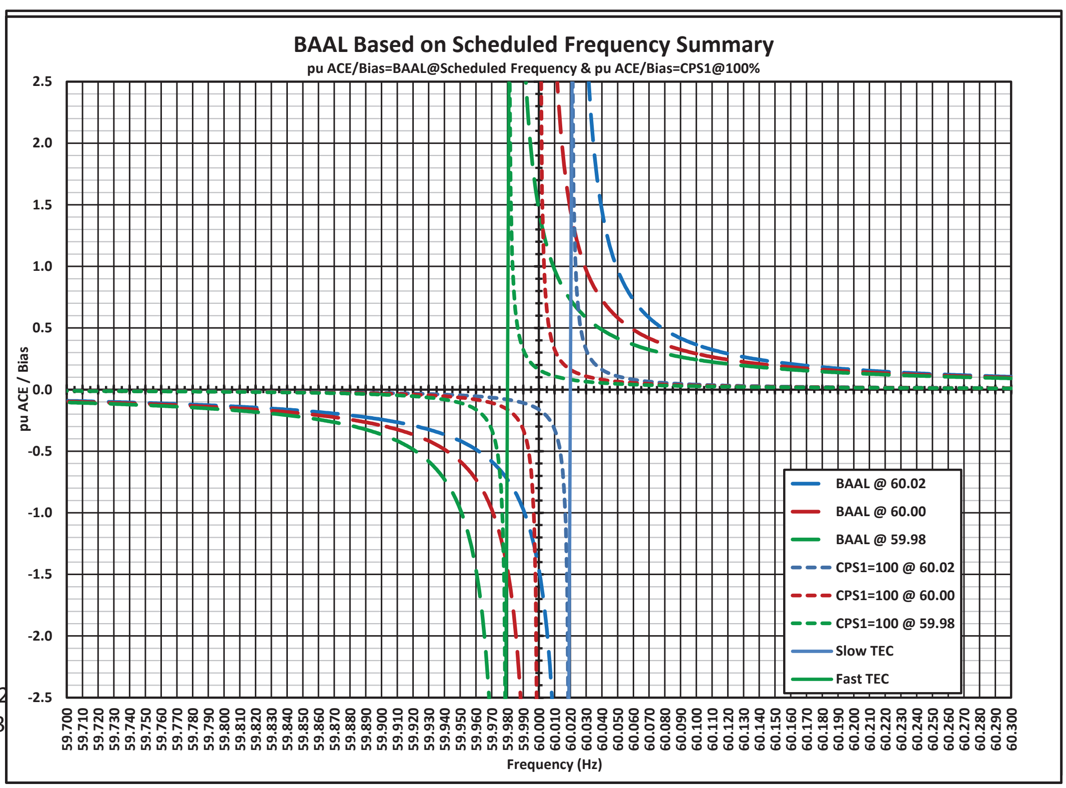

Figure 8. BAAL Based on Scheduled Frequency Summary

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

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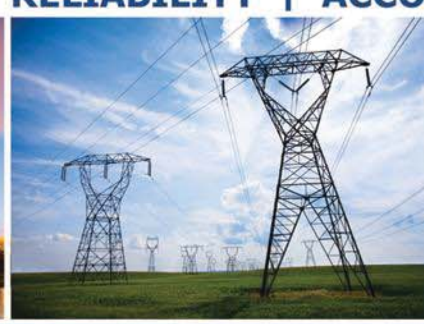


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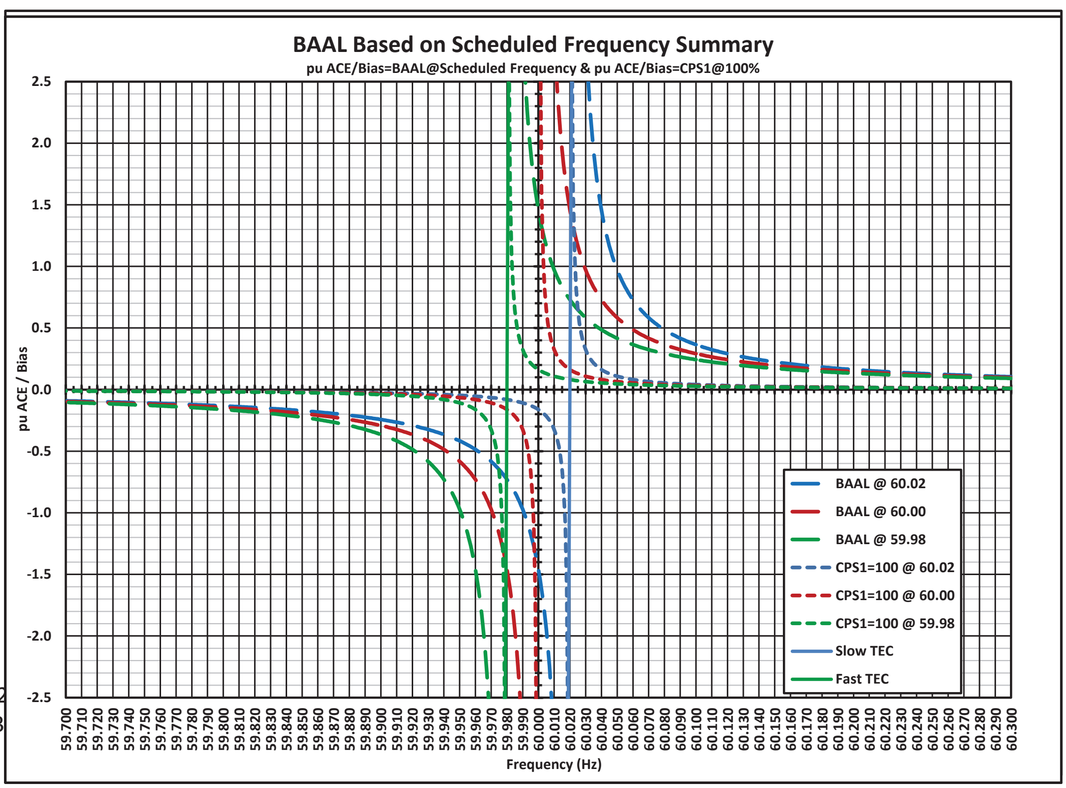

Figure 8. BAAL Based on Scheduled Frequency Summary

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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}. $AVG10\text{-minute}(ACE_i) \le L_{10}$ 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.

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}. $AVG10\text{-minute}(ACE_i) \le L_{10}$ 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, ~~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.

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.

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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 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

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard. This proposed draft standard will be posted for a 45-day formal comment period and 10-day successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third posting	July/August 2013
2. Successive Ballot	August 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.

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3 as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

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.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$ 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 * 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 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.)

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**
2. **Number: BAL-002-2**
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

Applicability is determined on an individual event basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

4.1. Balancing Authority

4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.2. 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 effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum

of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.

1.1. The required reporting form is CR Form 1.

1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity and for an additional five hours during a given calendar quarter, the Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1 and additional documentation of any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance 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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 70% or less of required recovery.
R2	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 5 hours but less than or equal to 15 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 15 hours but less than or equal to 25 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 25 hours but less than or equal to 35 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 35 hours.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.

Proposed Action Plan and Description of Current Draft:

This is the third posting of the proposed standard. This proposed draft standard will be posted for a 45-day formal comment period and 10-day successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Third posting	July/August 2013
2. Successive Ballot	August 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.

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection~~change to the responsible entity's ACE~~.
C. Sudden restoration~~loss~~ of a ~~known~~ load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection~~500 MW~~ and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting~~able~~ Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3~~)~~ as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

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 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.)

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual event basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

4.1. Balancing Authority

4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.2. 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 effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. ~~Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, t~~The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, ~~demonstrate that~~ within the Contingency Event Recovery Period, ~~the Responsible Entity~~ return~~ed~~ its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting~~able~~ Contingency Event ACE Value was positive or equal to zero):
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and

- Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve~~Event~~ Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

Or,

- Its Pre-Reporting~~able~~ Contingency Event ACE Value, (if its Pre-Reporting~~able~~ Contingency Event ACE Value was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve~~Event~~ Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.

1.1. The required reporting form is CR Form 1.

1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

R2. Except during the Responsible Entity's Contingency Event~~Disturbance~~ Recovery Period and the Responsible Entity's Contingency Reserve Restoration~~Recovery~~ Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity and for an additional five hours during a given calendar quarter, the~~each~~ Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1 and ~~, including~~ additional documentation of~~on~~ any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with ~~the amounts identified in~~ Requirement R2~~ except within the first 105 minutes following an event requiring the activation of Contingency Reserve~~.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 70% or less of required recovery.
R2	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 5 hours but less than or equal to 15 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 15 hours but less than or equal to 25 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 25 hours but less than or equal to 35 hours.	In each calendar quarter, the Responsible Entity had Contingency Reserves but its Contingency Reserve was deficient for more than 35 hours.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency, or the amount listed below for the applicable Interconnection and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

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:

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

Reporting ACE is calculated in the Western Interconnection as follows:

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.

$I_{ATEC} = \dfrac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y) * H}$ 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 * 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 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.)

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 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 pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

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Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden Loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility~~ies~~;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection~~change to the responsible entity's ACE~~.

C. Sudden restoration ~~loss~~ of a ~~known~~ load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency, or the amount listed below for the applicable Interconnection~~500 MW~~ and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting~~able~~ Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other ~~NERC~~ contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.~~.~~

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.

$$I_{ATEC} = \frac{\mathrm{PII}_{\mathrm{accum}}^{\mathrm{on/off\ peak}}}{(1-Y)*H}$$ 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 * 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 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.)

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities
N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 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 pursuant to the laws applicable to such ERO governmental authorities.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Unofficial Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control BAL-002-2 Contingency Reserve for Recovery from a Contingency Event

Please **do not** use this form to submit comments on the proposed revisions to BAL-002-2 Contingency Reserve for Recovery from a Contingency Event. Comments must be submitted using the electronic comment form by 8 p.m. ET on **Monday, September 16, 2013**.

If you have questions please contact Darrel Richardson (via email) or by telephone at (609) 613-1848.

Background Information:
Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard.

- Modified the definition for a Balancing Contingency Event to provide additional clarity.
- Modified the definition for a Reportable Balancing Contingency Event to use Interconnection specific thresholds instead of a continent wide threshold.
- Modified the definition for Pre-Reporting Contingency Event ACE Value to provide additional clarity.
- Modified the definition for Reserve Sharing Group Reporting ACE to provide additional clarity.
- Modified the definition for Contingency Reserve to provide additional clarity.
- Modified Requirements R1 and R2 to provide additional clarity.
- Modified the VSL for Requirement R1 to provide additional clarity.
- Modified the Background Document to provide additional clarity.

Questions

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.

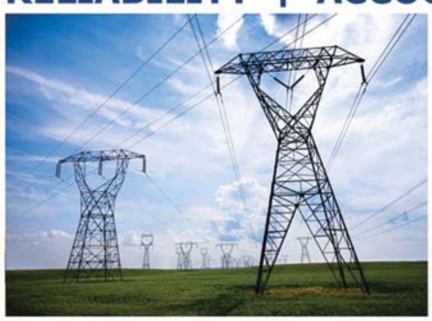
Comments:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

RELIABILITY | ACCOUNTABILITY



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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's most severe single contingency.

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question on who is the applicable entity and assures the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 solely a performance standard. The primary objective of BAL-002-2 is to assure the applicable

entity balances resources and demand and returns its Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing contingency reserve definitions primarily focused on generation and not demand side management. In order to meet FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with demand side management.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complimented each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event. And without a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least:

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero),
    - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting Ace within the Contingency Event Recovery Period, and
    - further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

, or

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC

1.1 The required reporting form is CR Form 1.

1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entity(s) to have a clear way to demonstrate compliance and support the Interconnection to the full extent of MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of contingency reserve.

Additionally, R 1 is designed to assure the applicable entity must use reserve to cover a Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in

Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the drafting team elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of the FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the required contingency reserve response and measured contingency reserve response are computed and compared as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.
- The measured contingency reserve response is equal to one of the following:
    - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events

occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.

- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

• Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:

- If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
- If the required contingency reserve response is greater than zero,
  - And the measured contingency reserve response is greater than or equal to the required contingency reserve response, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - And the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - And the measured contingency reserve response is less than the required contingency reserve response but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((required contingency reserve response – measured contingency reserve response) / required contingency reserve response)).

The above computations can be expressed mathematically in the following 7 sequential steps, labeled as [1-7], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)

SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[2]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[3]**

If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 **[4]**

If REQ_CR_RESP is greater than 0, and,

MEAS_CR_RESP is greater than or equal to REQ_CR_RESP, then

COMPLIANCE = 100 **[5]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[6]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is greater than 0, and,

MEAS_CR_RESP is less than REQ_CR_RESP, then

COMPLIANCE = 100 * (1 – ((REQ_CR_RESP – MEAS_CR_RESP)/ REQ_CR_RESP)) **[7]**

Requirement 2

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity and for an additional five hours during a given calendar quarter, the Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to its Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the drafting team believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. Additionally, the drafting team understands that Responsible Entities available Contingency Reserve may vary slightly from MSSC during any time of the year. Thus, to allow for the five hours of exemption by calendar quarter, the drafting modified the requirement to reflect such an exemption. By including the exemption provides the necessary continuity between the requirement and the VSL.

Attachment 1

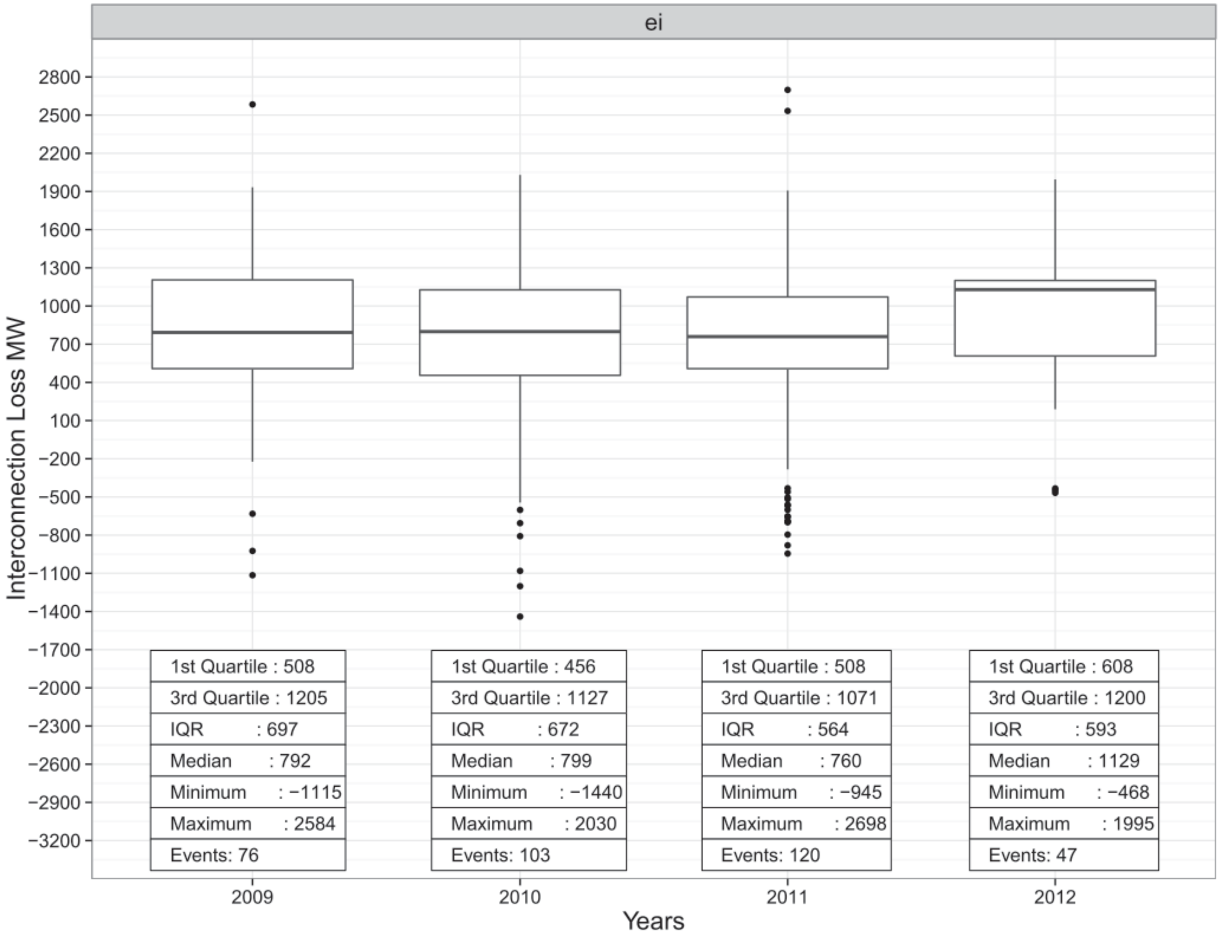
NERC Interconnections 2009-2012

Frequency Events Loss MW Statistics

For: NERC BARC Standard Drafting Team

Prepared by: CERTS

Date: November 2, 2012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Interconnection Loss MW
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Maximum : 1995
Events: 47
2009
2010
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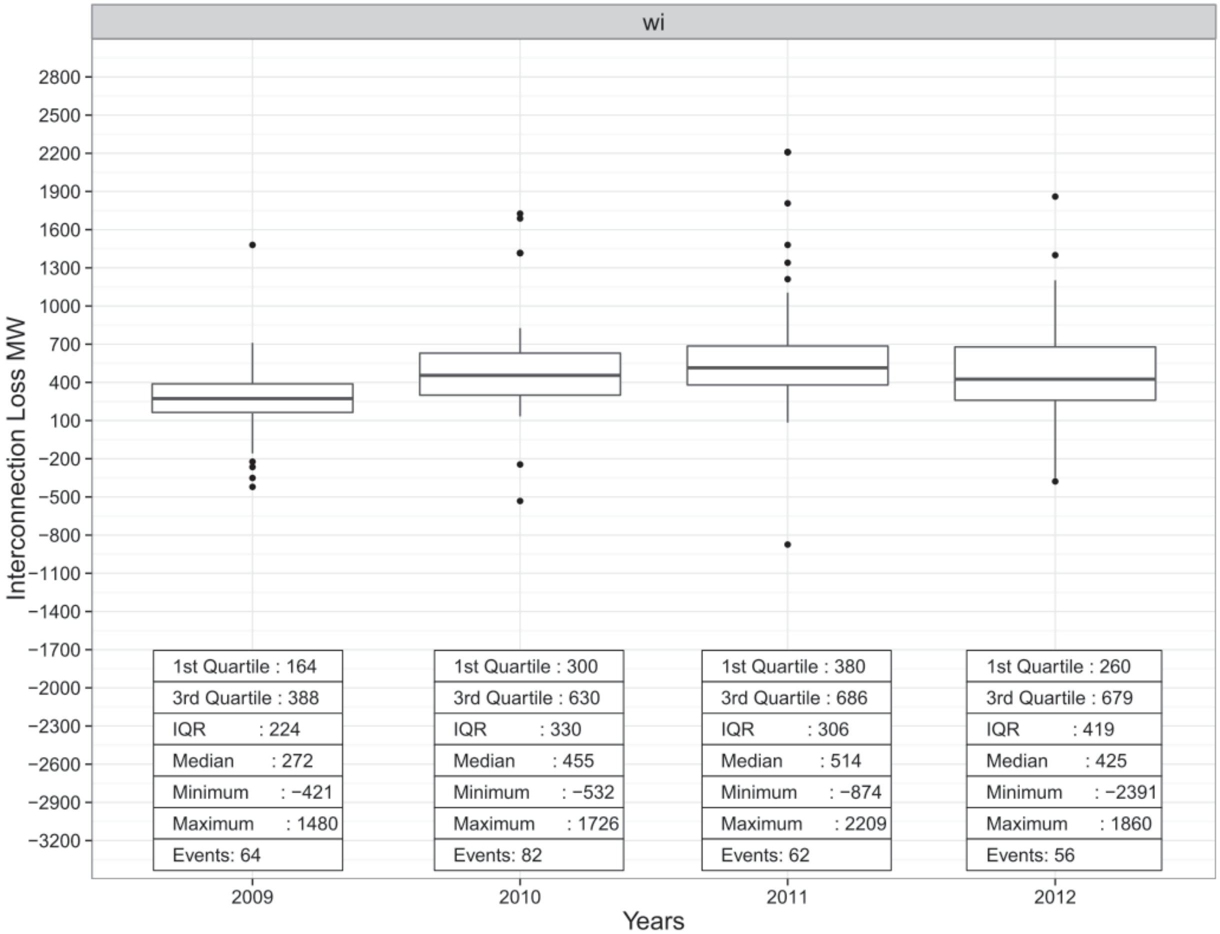
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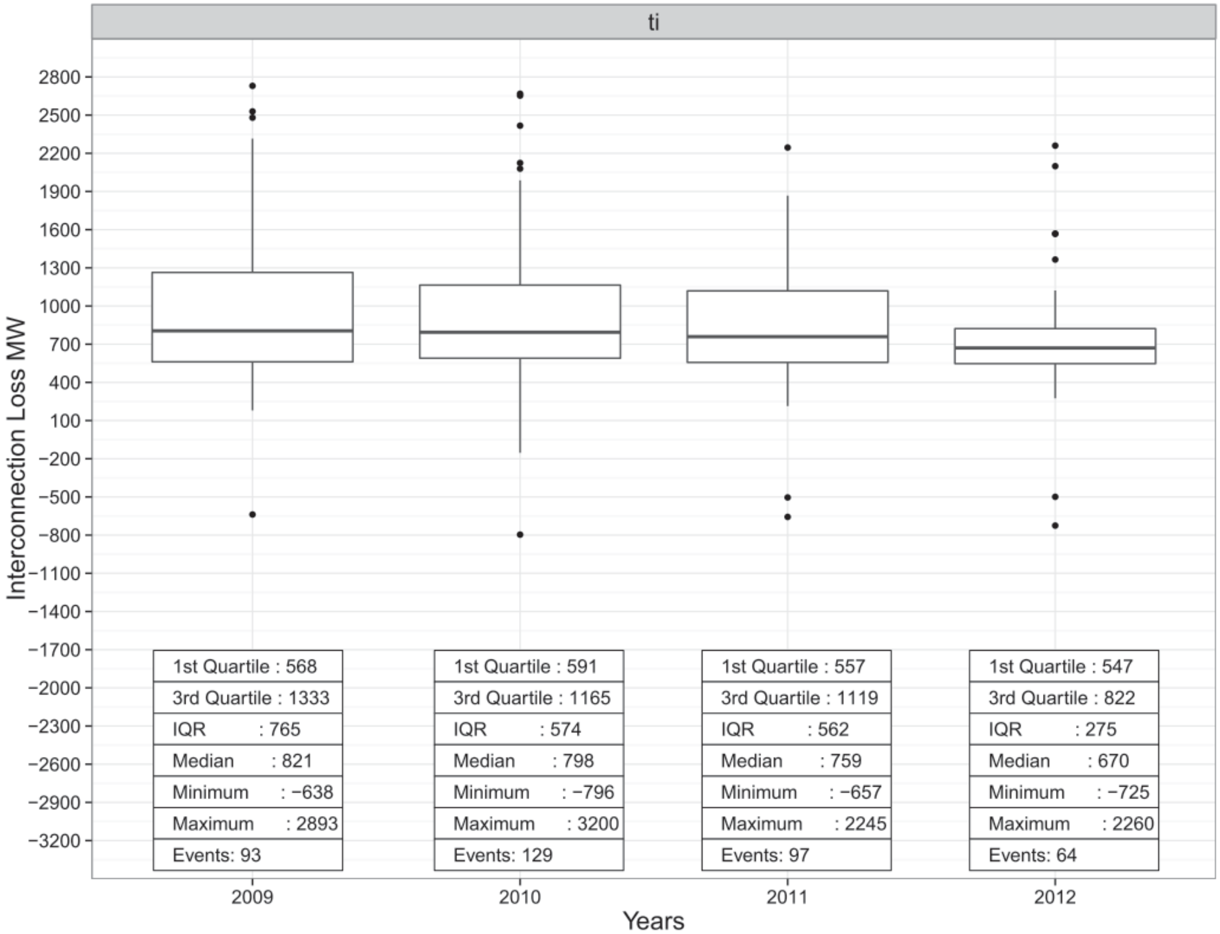
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3rd Quartile : 1333
IQR : 765
Median : 821
Minimum : −638
Maximum : 2893
Events: 93
1st Quartile : 591
3rd Quartile : 1165
IQR : 574
Median : 798
Minimum : −796
Maximum : 3200
Events: 129
1st Quartile : 557
3rd Quartile : 1119
IQR : 562
Median : 759
Minimum : −657
Maximum : 2245
Events: 97
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IQR : 275
Median : 670
Minimum : −725
Maximum : 2260
Events: 64
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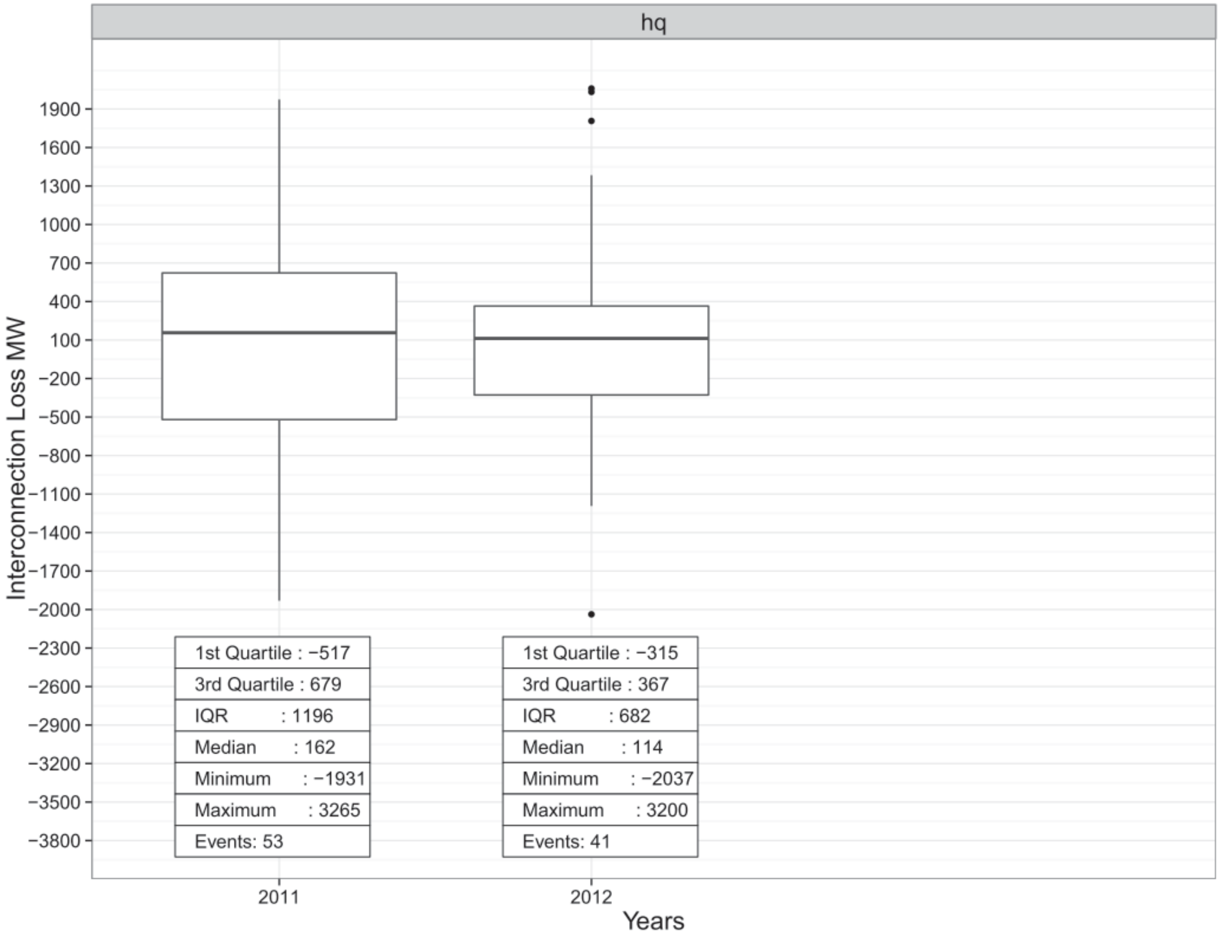
2012
Years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−2600
−2900
−3200
−3500
−3800
1st Quartile : −517
3rd Quartile : 679
IQR : 1196
Median : 162
Minimum : −1931
Maximum : 3265
Events: 53
1st Quartile : −315
3rd Quartile : 367
IQR : 682
Median : 114
Minimum : −2037
Maximum : 3200
Events: 41
2011
2012
Years

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RELIABILITY CORPORATION

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

RELIABILITY | ACCOUNTABILITY

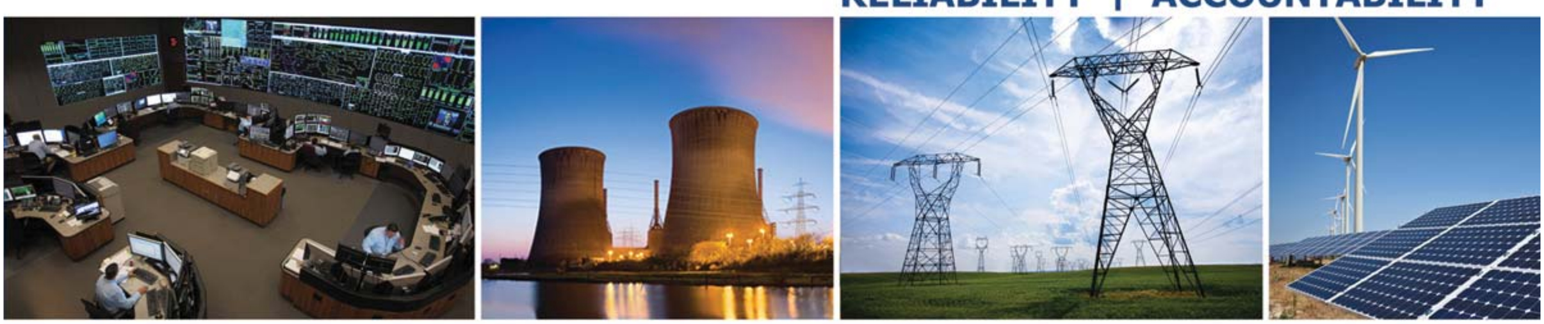

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Table of Contents

Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It~~They~~ replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15~~-~~ minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's most severe single contingency.

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question on who is the applicable entity and assures the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 solely a performance standard. The primary objective of BAL-002-2 is to assure the applicable

entity balances resources and demand and returns its Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, ~~and~~ the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the ~~industry,~~industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their~~its~~ Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing contingency reserve definitions primarily focused on generation and not demand side management. In order to meet FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with demand side management.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complimented each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event. And without a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

~~Except when an Energy Emergency Alert Level 2 or Level 3 is in effect, t~~The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, ~~demonstrate that~~ within the Contingency Event Recovery Period, ~~the Responsible Entity~~ return~~ed~~ its ACE to at least:

- Zero, (if its Pre-Reporting~~able~~ Contingency Event ACE Value was positive or equal to zero),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting Ace within the Contingency Event Recovery Period, and
  - further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their

Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,

, or

- Its Pre-Reporting~~able~~ Contingency Event ACE Value, (if its Pre-Reporting~~able~~ Contingency Event ACE was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC

1.1 The required reporting form is CR Form 1.

1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entity(s) to have a clear way to demonstrate compliance and support the Interconnection to the full extent of MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for C~~c~~ontingency R~~r~~eserve. It also recognizes that the loss of transmission as well as generation may require the deployment of contingency reserve.

Additionally, R 1 is designed to assure the applicable entity must use reserve to cover a Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After r~~R~~eviewing the data and industry comments, the drafting team elected to establish reporting threshold minimums for each respective Interconnection.~~concluded, based on the median, to establish a single continent-wide standard. Thus, some interconnections may report more events and some would report less.~~ This~~To~~ assures the requirements of the FERC Order No. 693 are~~were~~ met~~,~~. ~~the drafting team decided to capture the majority of the events having a significant impact on frequency;~~ T~~t~~he reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:~~500 MW.~~

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the required contingency reserve response and measured contingency reserve response are computed and compared as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.
- The measured contingency reserve response is equal to one of the following:

  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
  - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the required contingency reserve response is greater than zero,
    - ~~and~~And the measured contingency reserve response is greater than or equal to the required contingency reserve response, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
    - ~~and~~And the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
    - ~~and~~And the measured contingency reserve response is less than the required contingency reserve response but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((required contingency reserve response – measured contingency reserve response) / required contingency reserve response)).

The above computations can be expressed mathematically in the following 7 sequential steps, labeled as [1-7], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)

SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[2]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[3]**

If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 **[4]**

If REQ_CR_RESP is greater than 0, and,

MEAS_CR_RESP is greater than or equal to REQ_CR_RESP, then

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MEAS_CR_RESP is less than REQ_CR_RESP, then

COMPLIANCE = 100 * (1 – ((REQ_CR_RESP – MEAS_CR_RESP)/ REQ_CR_RESP)) **[7]**

Requirement 2

R2. Except during the Responsible Entity's Contingency Event~~Disturbance~~ Recovery Period and the Responsible Entity's Contingency Reserve Restoration~~Recovery~~ Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity and for an additional five hours during a given calendar quarter, the~~each~~ Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.

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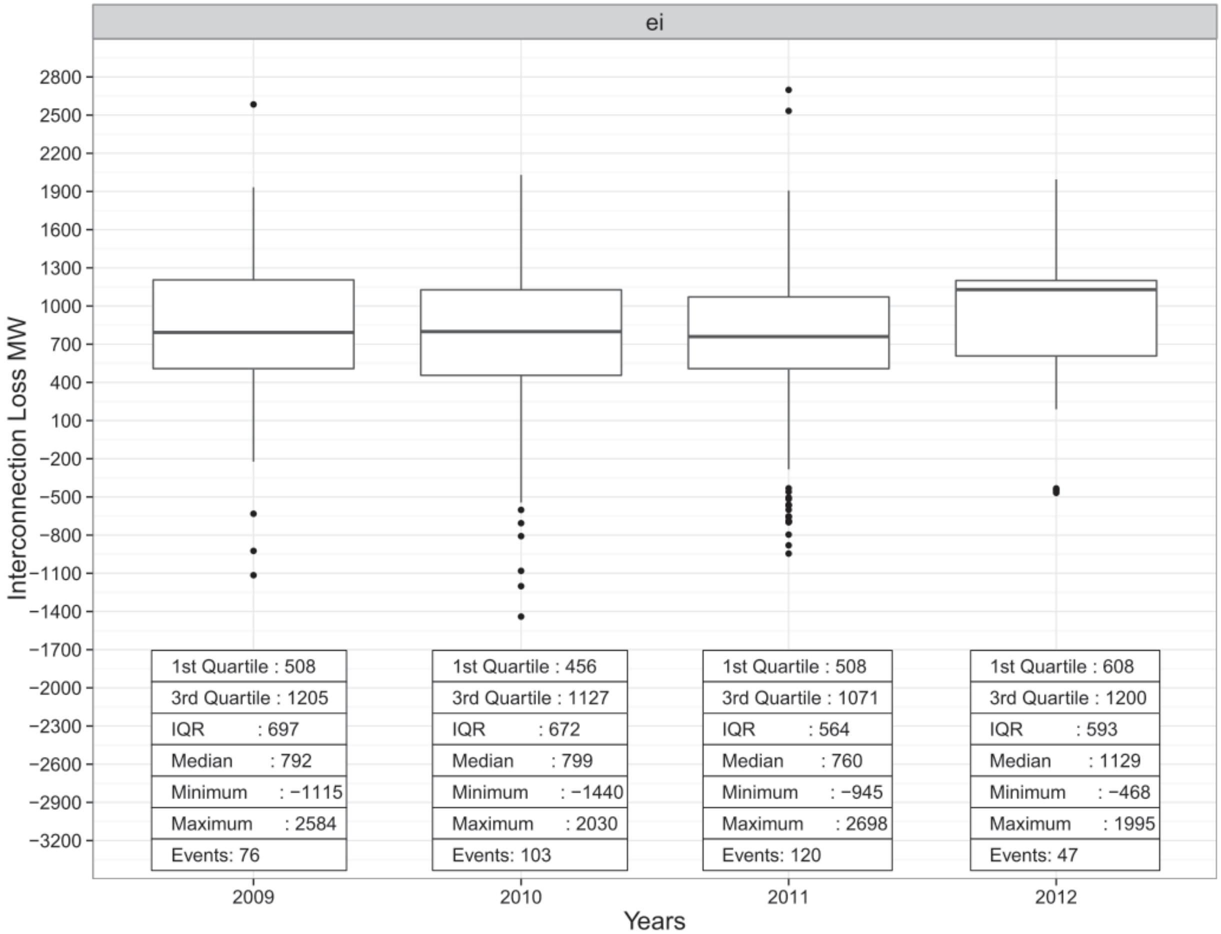
For: NERC BARC Standard Drafting Team

Prepared by: CERTS

Date: November 2, 2012

CERTS
Consortium for Electric Reliability Technology Solutions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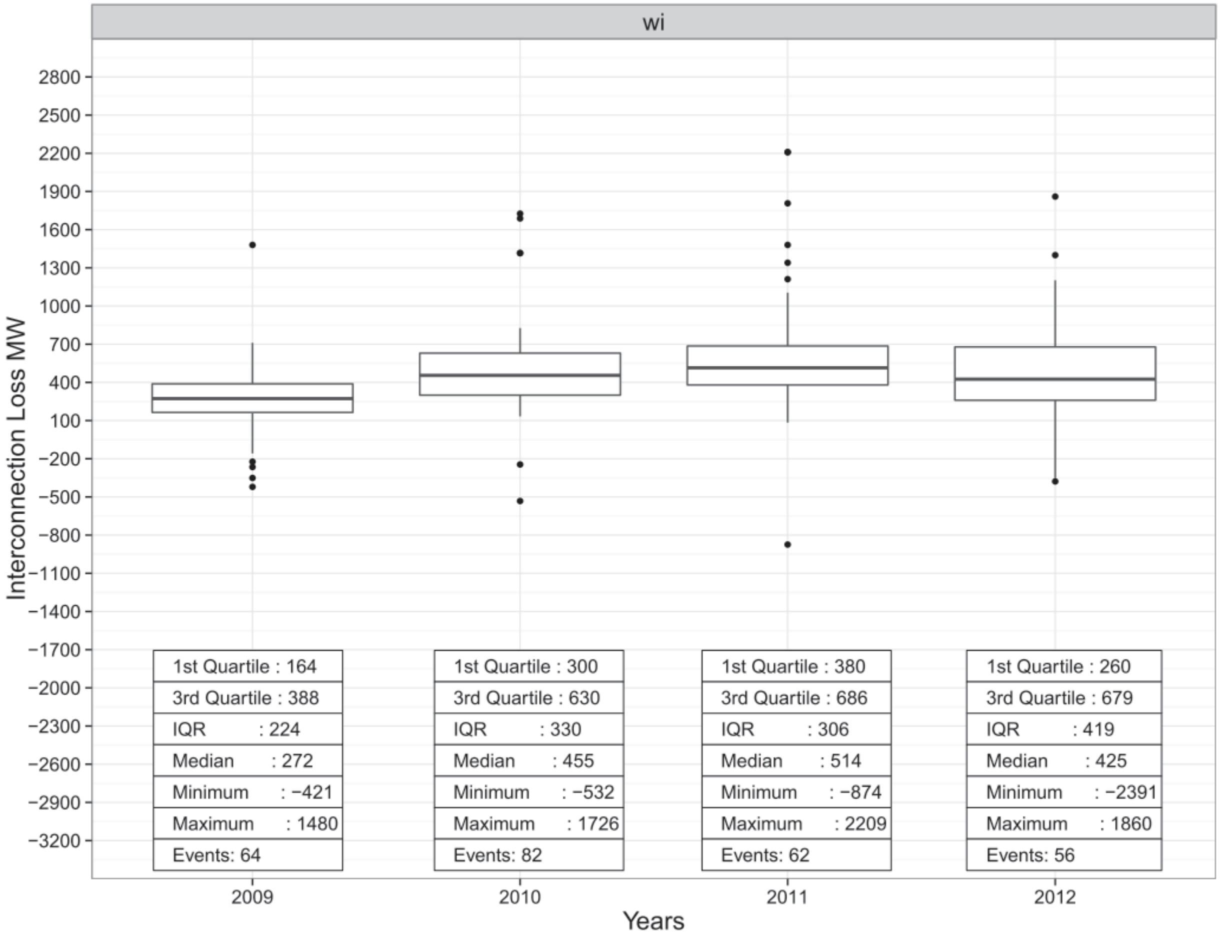
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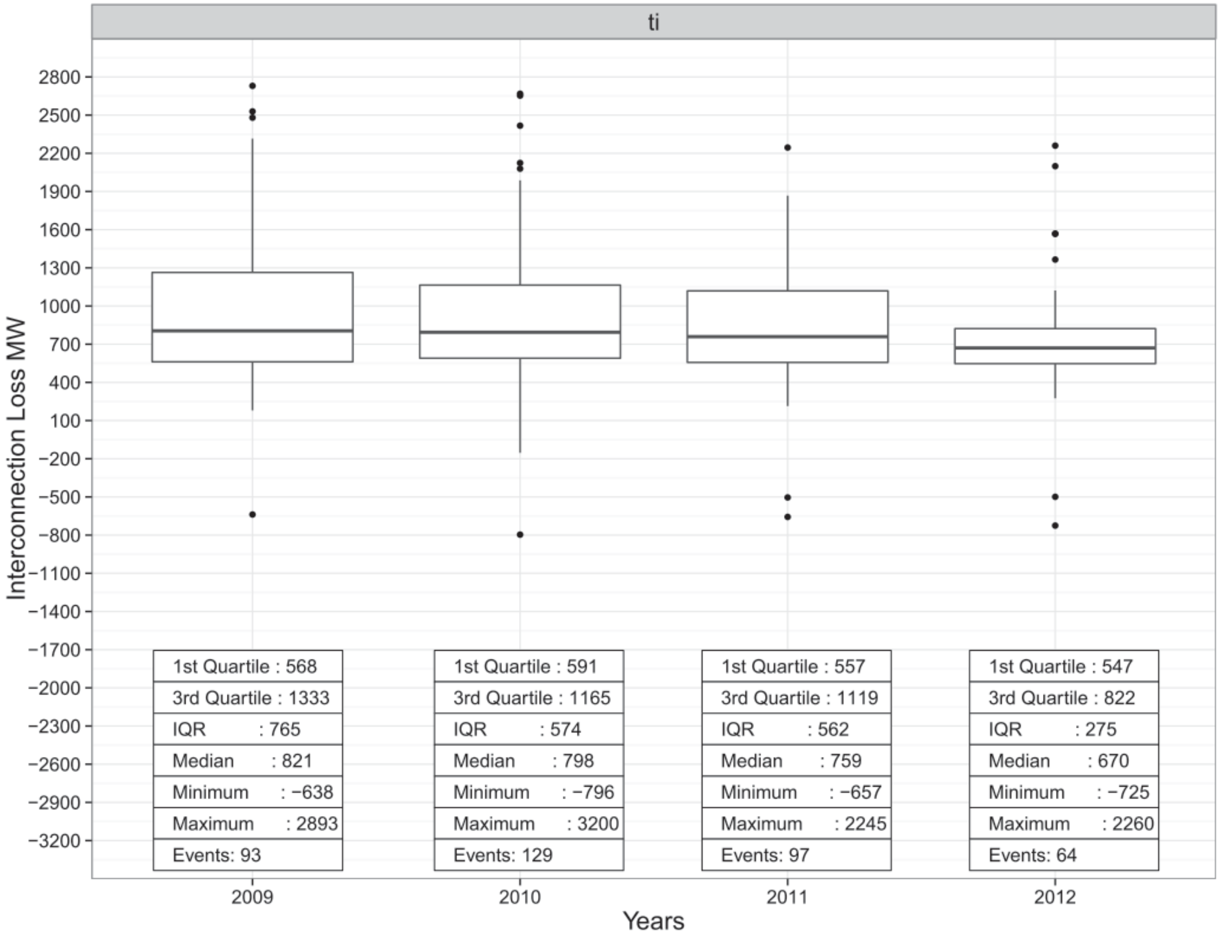
2012
Years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Interconnection Loss MW
2800
2500
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1900
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1300
1000
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−1700
−2000
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−2600
−2900
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1st Quartile : 568
3rd Quartile : 1333
IQR : 765
Median : 821
Minimum : −638
Maximum : 2893
Events: 93
1st Quartile : 591
3rd Quartile : 1165
IQR : 574
Median : 798
Minimum : −796
Maximum : 3200
Events: 129
1st Quartile : 557
3rd Quartile : 1119
IQR : 562
Median : 759
Minimum : −657
Maximum : 2245
Events: 97
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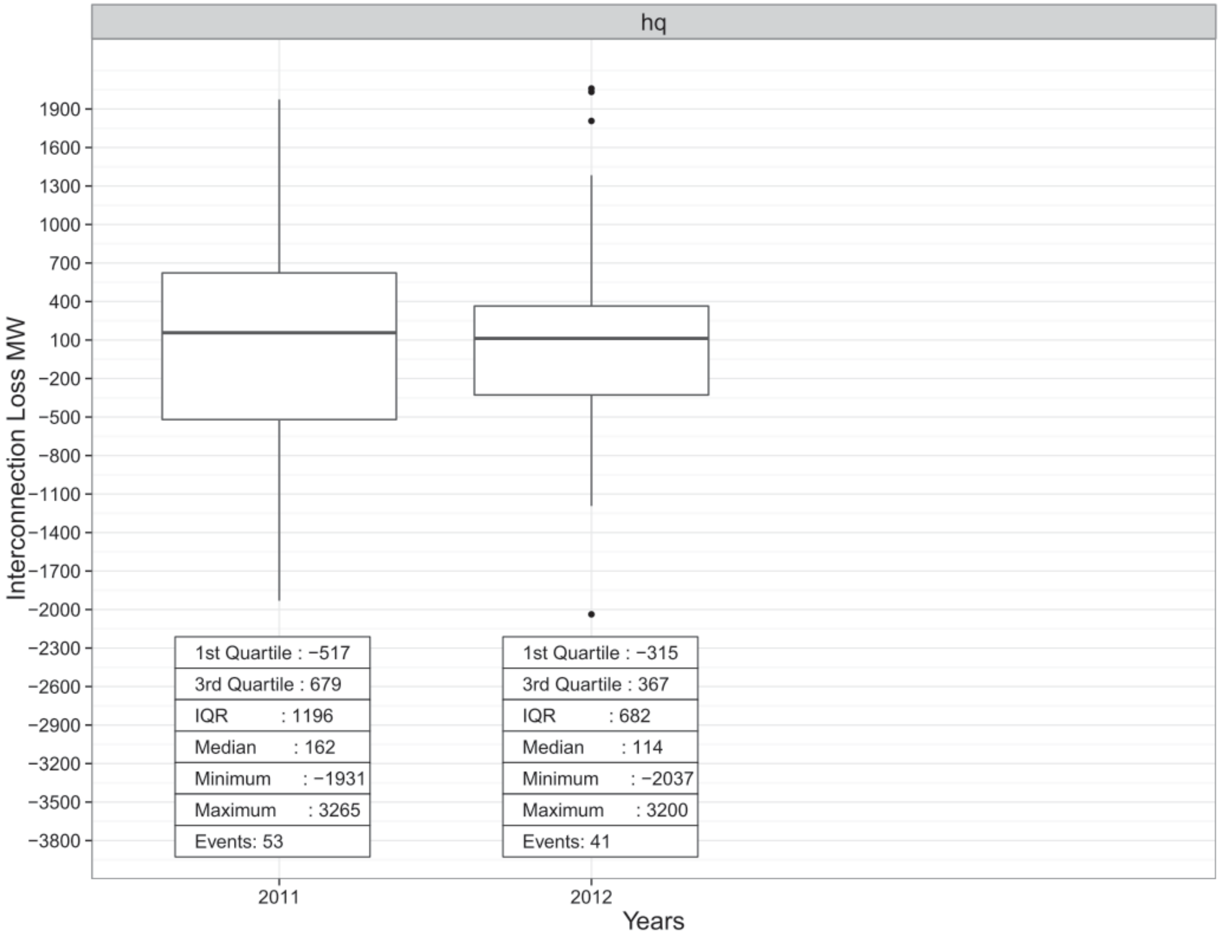
3rd Quartile : 822
IQR : 275
Median : 670
Minimum : −725
Maximum : 2260
Events: 64
2009
2010
2011
2012
Years


hq
Interconnection Loss MW
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−1700
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−2600
−2900
−3200
−3500
−3800
1st Quartile : −517
3rd Quartile : 679
IQR : 1196
Median : 162
Minimum : −1931
Maximum : 3265
Events: 53
1st Quartile : −315
3rd Quartile : 367
IQR : 682
Median : 114
Minimum : −2037
Maximum : 3200
Events: 41
2011
2012
Years

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-002-2, Contingency Reserve for Recovery from a Balancing Contingency Event. 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

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[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-002-2:
There are two requirements in BAL-002-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-002-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. Both requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, proposed BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. Both requirements in BAL-002-2 are assigned a “Medium” VRF. Requirement R2 is similar in scope to Requirement R1. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, proposed BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2 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-002-2 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-002-2 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 levels of noncompliance performance.	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 amount of time the entity is noncompliant.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. 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-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such	This Requirement has been moved into BAL-002-2 Applicability and “Additional Compliance Information” sections	Applicability 4.1. Balancing Authority 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. 4.2. Reserve Sharing Group 1.4. Additional Compliance Information The Responsible Entity may use Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		Reserve for any Balancing Contingency Event and as required for any other applicable standards.
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members.	This Requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for an reliability outcome and if violated would not cause separation, instability or cascading outages.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	This Requirement has been moved into BAL-002-2 Requirements R1 and Requirement R2	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
		clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. BAL-001-2 Requirement R2 **2.** Except during the Contingency Event Recovery Period and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources,		Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period,

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
or coordinated adjustments to Interchange Schedules.		and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. Contingency Event Recovery Period A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods: R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates	This Requirement has been moved into BAL-002-2 Requirement R1 and Reserve Sharing Group Reporting ACE	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.		Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. **Reserve Sharing Group Reporting ACE** At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that make up the Reserve Sharing Group.
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection. R6.1. The Contingency Reserve	This Requirement has been moved into the BAL-002-2 Requirement R1 and “Contingency Event Restoration Period” definition	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon:*

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
Restoration Period begins at the end of the Disturbance Recovery Period. R6.2. The default Contingency Reserve Restoration Period is 90 minutes.		*Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. Contingency Reserve Restoration Period:

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	Applicability 4.1. Balancing Authority 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. 4.2. Reserve Sharing Group 1.4. Additional Compliance Information The Responsible Entity may use Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		Reserve for any Balancing Contingency Event and as required for any other applicable standards.
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members.	This Requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for an reliability outcome and if violated would not cause separation, instability or cascading outages.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	This Requirement has been moved into BAL-002-2 Requirements R1 and Requirement R2	BAL-002-2 Requirement R1 1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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		clause (ii) of this bullet is greater than MSSC,
		
		Or,
		
		• Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative),
		  ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and
		  ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.
		
		1.1. The required reporting form is CR Form 1.
		
		1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
		Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. ~~1. Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to:~~ ~~• Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero):~~ ~~o less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ~~o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		~~Or,~~ • ~~Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative):~~ ○ ~~Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ○ ~~Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~ BAL-001-2 Requirement R2 **2.** Except during the Contingency Event Recovery Period

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		and Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3, each Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.		Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve

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		Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. ~~1. Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to:~~ ~~• Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero):~~ ~~O less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ~~O further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		~~Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,~~ ~~Or,~~ ~~• Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative):~~ ~~O Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ~~O Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~

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		Contingency Event Recovery Period A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single	This Requirement has been moved into BAL-002-2 Requirement R1 and Reserve Sharing Group Reporting ACE	BAL-002-2 Requirement R1 1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE

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Balancing Authority.) Compliance may be demonstrated by either of the following two methods: R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance		within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), ○ less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii)

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.		the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. ~~2. Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to:~~ • ~~Zero, (if its Pre-Reportable Contingency Event ACE Value was positive or equal to zero):~~ ○ ~~less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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		~~Period, and~~ ◦ ~~further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,~~ ~~Or,~~ • ~~Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative):~~ ◦ ~~Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ◦ ~~Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		~~all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~ **Reserve Sharing Group Reporting ACE** At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (as calculated at such time of measurement) of all of the Balancing Authorities that make up the Reserve Sharing Group.
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection. R6.1. The Contingency Reserve Restoration Period begins at	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition	BAL-002-2 Requirement R1 1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
the end of the Disturbance Recovery Period. R6.2. The default Contingency Reserve Restoration Period is 90 minutes.		<u>Value was positive or equal to zero):</u> ○ <u>less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period, and</u> ○ <u>Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,</u> <u>Or,</u> • <u>Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative),</u> ○ <u>less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur prior to that value of Reporting ACE within the Contingency Event Recovery Period,</u>

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
		and ○ Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC. 1.1. The required reporting form is CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. ~~1. Except when an Energy Emergency Alert Level 2 or 3 is in effect, the Responsible Entity experiencing a Reportable Balancing Contingency Event shall demonstrate that within the Contingency Event Recovery Period the Responsible Entity returned its ACE to:~~ • ~~Zero, (if its Pre-Reportable Contingency Event ACE~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
		~~Value was positive or equal to zero):~~ ◦ ~~less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~ ◦ ~~further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC,~~ ~~Or,~~ • ~~Its Pre-Reportable Contingency Event ACE Value, (if its Pre-Reportable Contingency Event ACE Value was negative):~~ ◦ ~~Less the sum of the magnitude of all subsequent Balancing Contingency Events that occur within the Contingency Event Recovery Period, and~~

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		~~o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Event Restoration Period when the sum referenced in clause (ii) of this bullet is greater than MSSC.~~ Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Formal Comment Period: August 2, 2013 – September 16, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: September 6-16, 2013

Now Available

A 45-day formal comment period for **BAL-002-2- Contingency Reserve for Recovery from a Balancing Contingency Event** is now open **through 8 p.m. Eastern on Monday, September 16, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting
A formal comment period is open through **8 p.m. Eastern on Monday, September 16, 2013.** Please use the electronic comment form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
A ballot for the standard and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development 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.

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Individual or group. (34 Responses)
Name (18 Responses)
Organization (18 Responses)
Group Name (16 Responses)
Lead Contact (16 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 (34 Responses)
Question 1 (0 Responses)
Question 1 Comments (24 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
There are concerns with the changes proposed to BAL-002 that were made without demonstrated need, and not proposed in the SAR nor directed in Order No. 693. The NERC Resources Subcommittee performed analysis when DCS was developed and found that the average time to recover from large unit trips was 15 minutes. Recent analysis for BAL-003 has found that all four Interconnections recover from large unit trips in about 5 minutes. Performance in recent years has been noticeably improved. This Standard should not be used to define terms not directly needed in the Standard (e.g. Reporting ACE). We disagree with the new definition of Contingency Reserve as it provides no guidance on how to objectively measure reserves. Regarding R1, there is no reasoning provided for the complexity added to the calculation. The current approach is well understood in the industry. The SAR does not discuss changing the measurement approach. In particular, DCS performance has always be calculated and reported on a quarterly basis. There have been no reliability issues that point to the need for making the DCS an event-by-event standard as is now proposed. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the “available hours” clock. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies they cover so they always have more reserves than their MSSC. This will increase costs to customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The Standard provides no clear definition on how contingency reserves are measured. Does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 10 or 15 minutes? What about demand response resources that aren’t directly measured? Finally, are the hours referenced in the Standard clock hours, any contiguous 60 minute periods, or the total minutes in a quarter divided by 60? The SAR directed cleaning up the V0 clutter in the Standard and address Order No. 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves 90 minutes thereafter. These should be the basis of this standard. We recommend the two core requirements be: R1. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall activate sufficient Contingency Reserve to comply with the DCS. R2. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall replenish its reserves within 105 minutes of the onset of the Reportable Event. The sizes of the Reportable Events for the Interconnections are acceptable. The reporting form should be similar to what is used today. The form should include the basis of the MSSC and the date of the last review of MSSC. We believe it is acceptable to put something in the Compliance Section of the Standard that notes if the same event greater than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency. We agree with the current direction of the Drafting Team to address the directive for the “continent-wide contingency reserve policy” is via the “Reserve Guidelines” document being developed. The document should provide guidance on how the BA assesses the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Once these terms are defined and commented on by the Industry in the document, NERC should add these types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. The policy could ask the BAs to initially review and assess their needs and report this to their RC. This would directly contribute to reliability by providing objective information to BAs and RCs in managing Energy Emergency Alerts. The format of the Requirements must be made to conform to NERC standards development rules, and a timeline should be provided for showing what is needed to have adequate contingency reserves. We also disagree with the new definition of Pre-Reporting Contingency Event ACE Value. The 16 second averaging requirement adds complexity to the calculation with no justification.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
• AZPS Comments: The wording of the qualifying contingency events that affect the disturbance ACE recovery value in R1 is hard to understand. • AZPS Proposed solution: offer an example(s) of overlapping contingency events and how they affect the target ACE recovery value.
Individual
Nazra Gladu

Manitoba Hydro
Manitoba Hydro is in support of this revised standard.
Group
Salt River Project
Bob Steiger
The draft standard introduces several magnitudes of complexity when compared with the existing standard. We understand and appreciate the reasoning behind accommodating preceding and subsequent contingency events in a measured recovery. However, our BA could not grasp the concept of how compliance would be determined until they downloaded and used the “CR Form 1” spreadsheet. This was the only way they could comprehend how the preceding and subsequent events would be calculated into final compliance determination. The wording of a requirement should be clear and stand-alone. We favor the definition of the Reporting ACE and the designation of the ATEC ACE for the WECC. We are concerned that the complexity will ultimately result in many NO votes simply because of the difficulty to understand the compliance concept. I suggest the DT simplify the requirement language.
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC OC Review Group
Individual
John Bee
Exelon and its' affiliates
While we appreciate the work done since previous versions of the project, and recognize the clarity gained by eliminating reference to Balancing Contingency Events with a future impact to ACE, we feel that additional confusion has been inserted by the sub-points of R1. Given that the recovery requirement is a relatively short time-frame, the ability to quickly determine the recovery obligation is critical to the ability to ensure compliance. We appreciate that the drafting team is attempting to accommodate the notion that a prior Balancing Contingency Event might impact any future events, but the methodology given for determining the recovery threshold is overly complex, and represents a significant barrier to a system operator's ability to interpret the requirement in Real Time and respond appropriately. Additionally, the definition provided for Reportable Balancing Contingency Event inserts confusion as to which value is to be used for determining MSSC. The definition does not clarify whether the responsible entity is to independently elect whether to use: A)Its individual MSSC value or the Interconnection values provided B)The Interconnection values provided The definition should make clear which value is to be used, and under which circumstances (for example, a “lesser of” statement would be useful, here, if that is the intent)
Individual
Thomas Foltz
American Electric Power
AEP questions if this new version is an improvement over the current BAL-002-1. There are many more terms that are cross referenced and it will become a risk that operators will struggle to tie all the pieces together. This proposed standard, while it might be more flexible in some regards, might cause unnecessary confusion. AEP recommends changing the definition for Balancing Contingency Event to the following: “Any single event described below, or any series of such otherwise single events, with each separated from the next by less than one minute and, that causes a significant change to the responsible entity’s ACE caused by 1. Sudden loss of supply (generation or import), not including controlled shutdown of a unit. 2. Restoration of a load” Reserve Sharing Group: the addition of the “at the time of measurement” is now stated twice in the same sentence. We believe one of the references should be removed. R1.1 and R1.2 should be either footnotes or bullet points, but not sub requirements. R2 is very difficult to follow with all of the exceptions. Furthermore, it would be better to start with the expected obligation and have the exceptions to the rule follow in the sentence or maybe in a footnote. We do support some amount of a “grace period” during these events, however, what is the reliability basis for the 5 hour duration?
Individual
Michael Falvo
Independent Electricity System Operator
a. Definition of Balancing Contingency Event: The proposed definition addresses loss of resource, but there is no specific mention of loss of load which could also cause a change of sudden change to ACE requiring recovery as its loss of resource counterpart. Please add this condition so that ACE recovery also applies for sudden loss of load, or elaborate why loss of load is not considered important to correcting ACE or reliability. Also, we believe the words “and interchange” should be inserted in Item B so that it will read: “imbalance between generation, load and interchange on the Interconnection…” b. Definition of Reportable Balancing Event: We propose to change the word “or” to “and” in the part: Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser

amount of 80 percent of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection…" since we are addressing the greater value of A (loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency) and B (the amount listed below for the applicable Interconnection). c. We do not understand the basis of including the definition of Reporting ACE in this standard. The definition has received industry approval and adopted by the BoT as part of the BAL-001-2 standard. There does not appear to be any rationale provided in either the Comment Report or the background document or in this Comment Form. Also, this term is not referenced/used in this standard. d. We commented during the last posting that we didn't see the need to define the term Reserve Sharing Group Reporting ACE. This term is not referenced or used in the standard at all. On the other hand, if including RSG in the Applicability Section is intended to make it a Responsible Entity to simplify drafting of the requirements (by starting off with "Responsible Entity"), then the RSG should comply with a Reserve Sharing Group ACE – a term which has not been defined but which we would refer it to be the algebraic sum of the ACE among the participating BAs. The SDT in its response to our comment indicates that "the use of the term Responsible Entity requires the inclusion of this definition for Reserve Sharing Groups. The SDT eliminated Requirement R5.1 and R5.2 from the existing standard and moved the language to this definition." While we agree that the intent of R5.1 and R5.2 of the existing BAL-002-1 standard have been moved to this standard, we do not believe the important granularity has been retained. R1 requires the Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least:… ACE is currently defined as: "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 Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection." We thus interpret "its ACE" in Requirement R1 to mean a BA's ACE unless the RSG is explicitly mentioned in the requirement. If this is to be interpreted as the Responsible Entity's ACE which also include the RSG as it is included in the Applicability Section, then a term Reserve Sharing Group ACE will need to be defined, or some explicit language be added to R1 to achieve the purpose that the SDT suggests in its response to our comments. In brief, the term Reserve Sharing Group Reporting ACE is not needed as it is not referenced in the standard and serves no purpose. To include the obligation for REG to meet group ACE, a term Reserve Sharing Group ACE needs to be defined instead. e. In general, we do not agree with the use of this standard to define terms not directly needed in the standard (e.g. Reporting ACE). f. We do not see the need for R2 when there is already a requirement to meet the DCS. While the trigger for meeting DCS is the occurrence of a Reportable Balancing Contingency Event which is linked to the Most Severe Single Contingency may not be at the MSSC level, the requirement to carry a prescribed amount of reserve is unnecessary for so long as the Responsible Entity meets the DCS requirement. R2 as proposed presents the "how", not the "what". g. This standard needs only to have very simple and plain language to require each BA and those engage in RSG to: • Meet DCS requirement within 15minutes • Replenish reserve within a certain time period to prepare for meeting DCS cause by another event • (If necessary) Report the occurrence of reportable events
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC OC Review Group
Individual
Alice Ireland
Xcel Energy
Xcel Energy is voting no on the proposed standard due to issues with R1. It is our opinion that events greater than MSSC should not be covered at all by the revised BAL-002-2. Instead, those events are appropriately addressed under the recently approved BAL-001-2 Balancing Authority ACE Limit (BAAL) and TOP-007-0 that sets the limits on exceeding the IROL or SOL. Standards addressing the BAAL and IROL/SOL require an entity to address the reliability issue within 30 minutes. As part of our rational, if an entity does experience an event greater than its MSSC, it is possible that the entity will lose some if not all of the units carrying their reserves. If this occurs, the entity is unable to respond with all of its reserves as required by the proposed R1 in BAL-002-2. Therefore, Xcel Energy recommends the following modifications: 1. Change the definition for Reportable Disturbances to state that only those events 80 percent of the MSSC (or the appropriate level of loss by interconnection) up to the MSSC would be reportable. This would clarify that events greater than the entity's MSSC is not a Reportable Event under the NERC Standards. 2. Simplify the language in R1 to address multiple events within the period and include the limit of MSSC in this process. 3. The drafting team should also modify the background document and other related documents to clearly state that events greater than the MSSC are not in scope of BAL-002-2 and document how these events are already addressed utilizing the BAAL and IROL limitations.
Group
FirstEnergy
Larry Raczkowski
Agree
PJM
Group
SERC OC Review Group
Stuart Goza

Comments: Applicability Section: 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. • Further clarification is requested. Please review previous versions. The concern in this area is event-by-event participation versus general RSG membership R1 sub-bullet: less the sum of the magnitudes of all subsequent Balancing Contingency Events that occur Added in draft: “prior to that value of Reporting ACE” within the Contingency Event Recovery Period, and • Language still remains awkward and the SDT is requested to continue to refine. • Time line or something visual to clarify the requirement further o The SDT is encouraged to work on drafting an RSAW for this standard • The SDT is requested to review and confirm that the obligation to report occurs once the analysis is completed R1.1: SDT is requested to further clarify 1.1 to the extent possible • Question to the SDT: By having CR Form 1 in the standard would changes to the form have to go through a formal standard revision change? CR Form 1 is the NERC reporting form. • Consider adding a new R2.1.1 and R2.1.2 to further clarify the calculation for each of the two different entities (BA and RSG) R2. Except during the Added in draft: “Responsible Entity’s Contingency Event Disturbance” Recovery Period and Added in draft: “the Responsible Entity’s” Contingency Reserve Added in draft: “Restoration” Deleted in draft: “Recovery” Period, or during an Energy Emergency Alert Level 2 or 3 Added in draft: “for the Responsible Entity and for an additional five hours during a given calendar quarter, the” Deleted in draft: “each” Responsible Entity shall maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency. • R2 The SDT is requested to further clarify how contingency reserves are measured. • R2 The SDT is further requested to clarify the 5 hour calculation • R2 The SDT is requested to further define the 105 minute We agree with the current direction of the team to address the directive for the “continent-wide contingency reserve policy” is via with the “Reserve Guidelines” document being developed. The document should provide guidance on how the BA assesses the necessary amount of reserves as well as provide simple definitions of the different types of reserves. M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with “the amounts identified in Requirement R2 Deleted in draft: “except within the first 105 minutes following an event requiring the activation of Contingency Reserve”. • M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with Requirement 2. • M2: SDT is requested to clarify that the hourly data retention is limited to one number per hour which represents your contingency reserves for the hour • M2: SDT is requested to add “calendar quarter” to M2 The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC OC Review Group
Group
ACES Standards Collaborators
Ben Engelby
(1) SAR We have concerns with the proposed revisions to BAL-002, particularly when the changes were neither proposed in the team’s SAR nor directed in FERC Order No. 693. We do not agree with the use of this standard to introduce nine new defined terms, and defined terms that are not directly needed in the standard (e.g. Reporting ACE). The SAR directed the drafting team to clarify the language in the existing standard and to address Order 693 directives. The only two true requirements in the version zero standard are to recover from reportable events in 15 minutes and replenish reserves 90 minutes thereafter. These actions should be the basis of this standard. (2) Definition of Balancing Contingency Event There is nothing provided to justify the need of this term. There is a statement in the background document that the previous version of the standard was “broad and could be interpreted in various manners,” yet there have been no reliability issues or events that justify the need for further clarification. (3) Definition of Reportable Balancing Contingency Event We continue to question the definition of Reportable Balancing Contingency Event. There is no explanation for why Reportable Disturbance is not a satisfactory definition as used in the existing standard and why it is replaced with Reportable Balancing Contingency Event. The numbers provided for each interconnection appear to be arbitrary. The background document explains that the drafting team decided “to capture the majority of events having significant impact on frequency” by setting the threshold to 80 percent of the MSSC, but it did not explain why it was important “to capture the majority of events.” There is no justification provided for changing the sizes of Reportable Events for the Interconnections from 80 percent. Where did the thresholds come from? We would like additional clarification and technical justification. (4) Definition of Pre-Reporting Contingency Event ACE Value Additional justification is necessary to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, it is not consistent with BAL-005-0.2b which requires ACE calculation on at least a six-second basis. A BA using a six-second sample rate could be viewed as being out of compliance if an entity used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any glitches in the data. What does an entity do if a scan was skipped or there was a data spike? More samples would make it less likely for this to be an issue. (5) Definition of Reserve Sharing Group Reporting ACE We believe the definition as proposed is already a common understanding and is not needed. We simply do not see how it adds value. Further, having multiple definitions for ACE creates unnecessary confusion. (6) Definition of Contingency Reserve We disagree with the new definition of Contingency Reserve as it provides no guidance on how to objectively measure reserves. Please strike the last sentence of the definition. It is an explanation of what may constitute contingency reserve and is not actually part of the definition. It

should be included in the background document. We understand the reason for the inclusion may be in response to a directive to further the Commission's policy on expanding the use of DSM. However, the use of DSM has expanded significantly since the directives were issued and could be said to have been "overcome" by events. It is well understood within this industry that DSM may be used as a resource. The drafting team could include an explanation in the application guidelines or the background document that would explain that DSM could be used among other resources. (7) Definition of Reporting ACE We do not see the benefit of including a three-page definition for this standard. As stated above, we do not agree with adding terms that are not directly needed in this standard. Furthermore, the kind of information included in this definition is more appropriate to include in a technical guideline or the application guidelines section. (8) Purpose of Standard The purpose statement still needs to be modified. We continue to recommend striking the following language "balances resources and demand," because these actions are addressed by BAL-001. The purpose of the standard should state: "To ensure the BA or RSG recover ACE following a Reportable Balancing Contingency Event." (9) Comments on R1 There is no technical justification for the complexity added to the calculation, and this is out of scope of the SAR. The SAR does not discuss changing the measurement approach of DCS performance from being calculated and reported on a quarterly basis. The current approach is well understood in the industry. Therefore, we suggest modifying the standard to remove the complexity. Proposed Solution for R1: "R1. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall activate sufficient Contingency Reserve to comply with the DCS." (10) Comments on R2 This requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. The original Policy 1 noted many reasons for operating reserves. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. A BA should not be restricted to deploying it only for contingent events. There may be other reasons for a BA to have a large negative ACE (i.e. units don't ramp as expected) and the BA should be free to call upon its contingency reserve to recover ACE in such a situation. Since the FERC directive that is driving this requirement is to establish a continent wide policy on contingency reserve, a better solution would be for NERC to write an operating policy describing appropriate uses of various types of contingency reserves. A guideline document would provide better details for an operating policy than a requirement. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingencies they carry so they always have more reserves than their MSSC. This will increase costs to end-users without a demonstrated need. Furthermore, there is no data indicating that operating reserves carried by BAs today are insufficient. Proposed Solution for R2: "R2. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall replenish its reserves within 105 minutes of the onset of the Reportable Event." (11) VSLs for Requirement R1 and Requirement R2 We disagree with the VSLs for both requirements. The VSLs significantly increase the compliance burden for registered entities without a technical justification. DCS compliance should continue to be determined by a quarterly average of response to events. Thus, failure to recover ACE for two events within the same quarter would be a single violation. We disagree with the proposed VSLs, as they would treat each event as a separate violation. The VSLs for Requirement R2 need to be justified. There is no explanation provided for the values chosen for the various thresholds. For example, the Lower VSL covers contingency deficiency for a period of 5 to 15 hours. Why shouldn't this go to 20, 30, 40 or any other number of hours? Without a justification, we can only assume the numbers were selected arbitrarily. While we understand from the response to comments that the modifications are intended to reflect actual enforcement practices, there have been no reliability issues or events that justify the need to shift the DCS to an event-by-event standard. NERC enforcement staff can submit comments requesting changes to the standards to reflect enforcement practices and FERC can clearly issue directives for changes once the standard is submitted for their approval. We have not seen any directives from FERC or comments from NERC enforcement staff regarding the need to revise the quarterly calculation. However, this raises bigger concerns in that the response implies that enforcement has not been consistent with the current common understanding of a quarterly calculation for DCS within the standard. If enforcement has not been consistent with the existing standard, then that issue needs to be addressed outside the standards development process and settled before the standard is changed to reflect a different period for the calculation DCS compliance. (12) Compliance Section of Standard The data retention required for the current versions of this standard is too long. BAs submit monthly data to their regional entities, so they should not be required to retain three years worth of data. No more than six months of data is necessary. (13) Technical Background Document We agree with the current direction of the team to address the directive for the "continent-wide contingency reserve policy" is via the "Reserve Guidelines" document being developed. The document should provide guidance on how the BA assesses the necessary amount of reserves as well as provide simple definitions of the different types of reserves subject to industry comment. We suggest drafting team retain the original language regarding the R1 that requirement applies except during EEAs 2 and 3. While we agree with the compliance exception, the language was moved to component 1.2 and does not comport with the statements from NERC's August 10, 2009 filing indicating the purpose and use of numbered components. Specifically, the filing indicates that numbered "components" will be used for parts that "contribute to the achievement of the reliability objective of the main requirement, but that individually do not achieve a reliability objective separate from the main requirement." We do not believe component or part 1.2 could be viewed as "contributing to the achievement of the reliability objective." Rather, it is a compliance exception and should be included as an exception clause similar to the way it was written in the prior version of the standard. Part 1.1 could be viewed as a paragraph 81 requirement meeting criterion B4 on reporting. NERC and the Regional Entities already require registered entities to use various reporting forms that are not identified in a standard. The Rules of Procedure allow NERC and the Regions to request data, thus, we think this is simply not necessary to document the need to use the CR Form I 1 in the requirement. Thank you for the opportunity to comment.
Individual
John Seelke
Public Service Enterprise Group

Agree
PJM Interconnection, L.L.C.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst votes in the Negative 1), ReliabilityFirst believes the introductory paragraph within the Applicability section is unclear as written, which could lead to unintended compliance implications; 2) the standard should not rely on Energy Emergency Alert Level 2 or Level 3 which are defined within another standard. The requirements of the standard should stand on their own merit and not rely on conditions defined within an attachment within another standard and; 3) it is unclear whether the use of the referenced CR Form 1 is an actual requirement and is enforceable. ReliabilityFirst offers the following comments for your consideration: 1. Applicability Section – ReliabilityFirst believes the introductory paragraph within the Applicability section is unclear as written. The language stating “on an individual event basis” is ambiguous and can lead to questions on the Applicability of this standard. ReliabilityFirst believes the intent of this language is meant to apply to Reportable Balancing Contingency Events. ReliabilityFirst recommends the following for consideration: “Applicability is determined on an individual [Reportable Balancing Contingency Events] basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.” 2. Reference to Energy Emergency Alert Level 2 or Level 3 - ReliabilityFirst believes referencing Energy Emergency Alert Level 2 or Level 3 within this standard without defining it within the standard itself is incorrect and troublesome for two reasons. First, the term Energy Emergency Alert Level is not a NERC defined term and the levels are only referenced in Attachment 1 of EOP-002-3. Entities which are not familiar with Attachment 1 of EOP-002-3 may have no idea what constitutes an Energy Emergency Alert Level 2 or Level 3. Second, ReliabilityFirst believes the BAL-002-2 should stand on its own merit and not rely on conditions within an attachment within another standard. For example, if the Energy Emergency Alert levels designations ever change (as a result of modifications to Attachment 1 of EOP-002-3), this has the potential to have an impact on the intent of the BAL-002-2 standard. For the two reasons noted, ReliabilityFirst recommends formally defining all the Energy Emergency Alert Levels within the NERC Glossary of Terms. This would be a valid option since this term would now be used in multiple standards (e.g., EOP-002-3 and BAL-002-2). 3. Requirement R1, Part 1.1 – As written, it is unclear whether this is an actual requirement requiring the entity to use the CR Form 1? The parent requirement R1 requires the Responsible Entity to return its ACE to either zero or its Pre-Reporting Contingency Event ACE Value, but does not require the use of the CR Form 1. If it is the intent of the SDT to require the Responsible Entity to use the CR Form 1, ReliabilityFirst recommends making a new standalone requirement such as “The Responsible Entity shall use the CR Form 1 for compliance calculations for Reportable Balancing Contingency Events.” Furthermore, the CR Form 1 is not associated with the standard itself. Without this form being associated as an attachment or appendix to the standard, how will the Responsible Entity know the location of the referenced form? Also, ReliabilityFirst believes there may be issues with regulatory approval absent the referenced CR Form 1 being included as part of the standard. ReliabilityFirst recommends including the CR Form 1 as either an attachment or appendix to the standard.
Group
SPP Standards Review Group
Robert Rhodes
On BAL-002-2: We would like to see further development of the qualifier ‘sudden loss’. Specifically what comprises a sudden loss? Naturally we all believe the opening of a unit breaker creates a sudden loss of generation but what about those events, such as unit runbacks, where there is no clear-cut line of distinction. We have experienced multiple contingencies where one of the units has tripped out right and the other lingers on for some time before eventually tripping. Depending upon when the clock starts, this could be interpreted to have occurred within one minute which could qualify the event as a reportable DCS event. We have talked to multiple REs as well as industry SMEs to determine exactly what the correct interpretation is in this situation. The way the standard is written there is no single, correct interpretation. Do we want to incorporate such criteria into the standard or could we find language which would provide additional clarification to assist in making that determination? This dilemma also extends to situations with imports where sudden loss is again not clearly defined. This becomes more and more of an operational nightmare when the variability of intermittent resources is taken into account. Demand-Side Management should be properly handled as a defined term from the NERC Glossary throughout the standard as well as the Background Document. We ask that the drafting team provide additional clarification on ‘active status’ found in the Applicability Section 4.1.1. We are most concerned by the incorporation of the 5-hour exclusion in R2. While on one hand we like the idea of some flexibility in the standard, providing such flexibility will not improve the reliability of the BES one bit. In fact it would decrease the reliability of the BES. We suggest removing that language as well as the last paragraph on Page 10 in the Background Document which details the reasoning behind the exclusion. CR Form 1 requires reporting on a single event basis rather than the quarterly reporting basis as currently exists. We recommend maintaining the existing quarterly reporting requirement. The argument here is the same as that used to support the exclusion of contingency events greater than MSSC. That exclusion is currently found in the Additional Compliance Information Section 1.5 of BAL-002-1 and has been moved into the requirements of the proposed standard. Likewise, the quarterly reporting criteria contained in the same Additional Compliance Information section of BAL-002-1 but in Section 2., could just as easily be incorporated into the new standard. We also support the following comments provided by Xcel Energy. Xcel Energy is voting no on the proposed standard due to issues with R1. It is our opinion that events greater than MSSC should not be covered at all by the revised BAL-002-2. Instead, those events are appropriately addressed under the recently approved BAL-001-2 Balancing Authority ACE Limit (BAAL) and TOP-007-0 that sets the limits on exceeding the IROL or SOL. Standards addressing the BAAL and IROL/SOL

require an entity to address the reliability issue within 30 minutes. Additionally, if an entity does experience an event greater than its MSSC, it is possible that the entity will lose some if not all of the units carrying their reserves. If it does, it is unlikely to be able to respond with all of its reserves as required by the proposed R1 in BAL-002-2. Therefore Xcel Energy recommends the following modifications: 1. The definition for Reportable Disturbances should be changed to state that only those events 80 percent of the MSSC (or the appropriate level of loss by interconnection) up to the MSSC would be reportable. Events greater than the entity's MSSC is not a Reportable Event under the NERC Standards. 2. Simplify the language in R1 to address multiple events within the period to address concerns in a similar manner. 3. The drafting team should also modify the background document and other related documents to clearly state that events greater than the MSSC are not in scope of BAL-002-2 and document how these events are already addressed utilizing the BAAL and IROL limitations. Xcel Energy recognizes that this proposal will likely cause concern amongst those who participate in the NERC Resources Subcommittee due to the loss of the quarterly reporting of events greater than the MSSC currently in the standard. We believe that these quarterly reports, for the evaluation of performance outside of the compliance process, should not be part of the standard. Instead, if NERC believes this process is needed, create a guideline or other means to have entities provide the needed information without using compliance with the standard as the reporting process. A clear separation between standards compliance and data evaluation would provide the industry the clarity of separation between compliance and data evaluation and study. Background Document: (Page number references are based on the clean version of the document.) To accentuate the potential for conflict between BAL-002 and EOP-002, we suggest rewording the first two (2) sentences of the last paragraph on Page 4 to read: 'Additionally, possible conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the conflict and to assure…' The following terms are contained in the NERC Glossary and should be consistently capitalized in the document: Operating Reserve Contingency Reserve Spinning Reserve Non-Spinning Reserve Frequency Response Obligation (new term associated with BAL-003-1) We recommend rewriting the first line of the second paragraph under Background and Rationale on Page 6 to read: 'By incorporating new definitions, including the modification of existing definitions, with the proposed R1 above, the …' Insert a 'the' in front of Consortium in the first line of the last paragraph on Page 6. Rewrite the third line of the paragraph under Violation Severity Levels on Page 7 to read: 'Contingency Reserve available and whether it has sufficient…' Insert a 'that' in front of BAL-002 in the first line of the second paragraph under Background and Rationale on Page 10.
Group
Duke Energy
Michael Lowman
Duke Energy's position is summarized as follows: a) This standard should not require 15-minute recovery for events greater than the MSSC, b) The standard should allow responsible entities to choose a lower reportable threshold and measure performance on a quarterly basis, and c) Tracking hourly amounts of Contingency Reserves maintained should be removed from this draft Standard and added to the guideline document. Regarding Requirement R1, Duke Energy would like to reiterate that no technical justification has been provided for requiring a 15-minute recovery from a Balancing Contingency Event. We believe those on the Standard Drafting Team also active in the development BAL-001-2 would acknowledge that the risk of any other significant event on the Interconnection occurring within the first event's Contingency Event Recovery Period or Contingency Reserve Restoration Period is so negligible that the risk does not on its own warrant such immediate action or compliance assessed on an event-by-event basis. It is our opinion that the recently-approved Balancing Authority ACE Limit (BAAL) in BAL-001-2 will drive the actions necessary to maintain Interconnection frequency within acceptable limits, as any event causing a large change in ACE and impacting frequency will be under that Standard's scrutiny. However, Duke Energy believes there is value in having a Reliability Standard that requires retaining contingency reserves capable of such immediate response and periodically testing the Balancing Authority's ability under DCS to implement its reserves. When DCS is viewed as a test of reserves maintained, one can understand the position that: a) For consistency across all Balancing Authorities, testing such capability for losses 80% and greater of the MSSC should typically cover each Balancing Authority reporting at least one event per quarter, b) Such tests should not include unplanned events above the MSSC, c) There shouldn't be an attempt to measure that reserves are maintained hourly, the proof is in the results, d) As a test to demonstrate reserves are maintained, the industry accepts that recovery at times may move Interconnection frequency further from scheduled frequency, such as during certain off-peak periods of high frequency, e) There is no need to capture every possible event under the scope of what's tested – it is more important that the criteria be clear to the operator (generation trip) on what's being tested, f) Recovery within 15 minutes is a reasonable expectation, as we don't want the contingent Balancing Authority leaning on the Interconnection support others provide too long, and g) Recovery within 15 minutes is a reasonable expectation, as the loss may be causing unanticipated flows (good or bad) that the contingent Balancing Authority should be first to correct It is our opinion that the points above all factored into the original approval of DCS, along with the industry acceptance that if the DCS was not met over a calendar quarter, that additional contingency reserves would be carried until Balancing Authority demonstrated its capability to meet those expectations. The quarterly reporting allowed for recognition that performance for every event may not be perfect, and that measuring compliance over the quarter is a better measure of the entity's overall performance and reserves maintained. Our points above are made as we believe that upon implementation of the BAAL, the value in retaining BAL-002 is in having a simple, results-based Standard to measure that reserves are adequately being maintained. We believe that this draft Standard goes beyond what is needed for reliable operations. It is our opinion that not all Regions share the concern that the 15-minute recovery is needed to mitigate transmission congestion problems, and we would suggest that perhaps such concerns should be addressed at the regional level. Duke Energy supports the comments of Xcel Energy regarding the proposed Requirement R1. It is our opinion that events greater than the MSSC should not be held to the 15-minute recovery criteria required under the revised BAL-002-2. Events greater than MSSC, typically driven by multiple unforeseen contingencies on the system, may require the Balancing Authority to coordinate its activities with the Transmission Operator for consideration of the transmission impact

of any reserve deployment or Interchange options. Under such circumstances we believe that the recently approved BAL-001-2 Balancing Authority ACE Limit (BAAL) and current TOP-007-0 that sets the limits on exceeding the IROL or SOL should be the Reliability Standards guiding the response required. In addition, and as part of our rationale, if an entity does experience an event greater than its MSSC, it is possible that the entity will lose some if not all of the units carrying their reserves. If this occurs, the entity is unable to respond with all of its reserves as required by the proposed R1 in BAL-002-2. Therefore, Duke Energy supports the following modifications suggested by Xcel Energy: 1. Change the definition for Reportable Disturbances to state that only those events 80 percent of the MSSC (or the appropriate level of loss by Interconnection) up to the MSSC would be reportable; this would clarify that an event greater than the entity's MSSC is not a Reportable Event under the NERC Standards. 2. Simplify the language in R1 to address multiple events within the period and include the limit of MSSC in this process. 3. The drafting team should also modify the background document and other related documents to clearly state that events greater than the MSSC are not in scope of BAL-002-2 and document how these events are already addressed utilizing the BAAL and IROL limitations. Duke Energy disagrees with measuring performance on an event-by-event basis. We believe such a metric will have a detrimental impact on reliability as responsible entities will have no reason to bring more resource losses under the scope of required compliance. The current standard, which allows a lower reportable threshold to be used in quarterly reporting, benefits the Interconnection and results in demonstrated activity under DCS for events that this proposed standard will push under BAL-001. Duke Energy also supports the comments of the SERC OC Review Team and agrees with the current direction of the team to address the directive for the "continent-wide contingency reserve policy" is via the "Reserve Guidelines" document being developed. The document should provide guidance on how the BA assesses the necessary amount of reserves as well as provide simple definitions of the different types of reserves. Regarding Requirement R2: Duke Energy agrees with the language in this Standard that recognizes that Contingency Reserves may be utilized to serve load during an Energy Emergency Alert Level 2 or 3. However, it is our opinion that this Standard should remain a results-based Standard and not burden responsible entities with such tracking of reserves maintained. Though an hourly average is proposed, it is not practical for a BA to track its Contingency Reserves in a manner where the System Operator would make the choice to increase its Contingency Reserves above the MSSC if it happened to drop below its MSSC for some time in the same hour – it is an unnecessary activity to bring into real-time operations. In addition, tracking reserves to this extent may result in Balancing Authorities not balancing their systems, to the extent allowed under BAL-001, in order to not dip into the Contingency Reserves which could, and should, be utilized as needed. Duke Energy recommends removing the hourly tracking of reserves from this standard and adding it to the guideline document. Though suggestions have been provided, Duke Energy does not support the adoption of Requirement R2 and agrees with the comments provided by MISO and SERC OC Review Team. Performance under the existing BAL-002 has been stellar without the need for an additional requirement to track Contingency Reserves to the extent prescribed. The current DCS is a very effective results-based standard. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability. Finally, Duke Energy suggests the following changes to the definitions in this standard: Duke Energy believes that Item B of Balancing Contingency Event should be removed because it is already covered under Item A. If the SDT disagrees, then item B should retain "the change to the responsible entity's ACE." The proposed draft language in item B, "imbalance between generation and load to the interconnection", opens up the possibility that upon the loss of transmission, the source Balancing Authority may continue to generate and sink Balancing Authority may continue to receive the energy without sufficient remaining transmission in place for the transfer. This will in turn overload facilities but not be captured as an "imbalance between generation and load on the Interconnection". See comments on proposed definitions beginning on next page. Proposed by SDT: Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. A. Sudden Loss of generation: a. Due to i. Unit tripping, ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or iii. Sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnectionchange to the responsible entity's ACE. C. Sudden restorationloss of a known load that was used as a resource that causes an unexpected change to the responsible entity's ACE. Suggested: Balancing Contingency Event: Any single event described in Subsections (I) or (II) below, or any series of such otherwise single events, with each separated from the next by less than one minute. I. Sudden loss of generation that causes an unexpected change to the responsible entity's ACE due to: a. Unit tripping, b. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or c. Sudden unplanned outage of transmission Facility II. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. NOTE: F Duke Energy took part A.a. and A.b. of the SDT proposed definition and incorporated it into "I"; Sudden loss of generation that causes an unexpected change to the responsible entity's ACE due to: F Changed the numbering from A. to I., B to II. and changed i., ii., iii. to a., b., c. Proposed by SDT: Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority). Suggested: Most Severe Single Contingency (MSSC): The magnitude of a single Balancing Contingency Event as a result of the greatest loss (measured in MW) of resource output used by a Reserve Serving Group (RSG) or a Balancing Authority that is not a member of an RSG. Proposed by SDT: Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output greater than or equal to the lesser amount of 80 percent of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection500 MW and occurring within a rolling one-minute interval based on EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity. • Eastern Interconnection - 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW Suggested: Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output that causes an ACE change greater than or equal to 80% of a Balancing Authority's or

Reserve Sharing Group's Most Severe Single Contingency or applicable amount listed below for each Interconnection, that occurs within a rolling one-minute interval of EMS scan rate data. The 80% threshold may be reduced upon written notification to the Regional Entity. • Eastern Interconnection - 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW Proposed by SDT: Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3) as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation. Suggested: Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event or contingency requirements such as an Energy Emergency Alert Level 1 or Level 2 as specified in the associated EOP Reliability Standard. The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation. NOTE: Replaced EEA Level 2 or 3 with EEA Level 1 or 2 in the definition. Contingency Reserve is already being utilized at EEA Level 3. I kept EEA Level 2 in the definition since Demand-side Management and Interruption of non-firm end use loads can be used, which both are resources of capacity used for Contingency Reserve. I've provided some detail below for EEA 2 and 3: • EEA 2 – Load management procedures in effect F the entity is no longer able to provide its customers' expected energy requirements and is designated an Energy Deficient Entity. F Energy Deficient Entity has implemented procedures up to, but excluding interruption of firm load commitments....DSM, Interruptible Load, etc. can be used time permitting • EEA 3 – Firm load interruption imminent or in progress (Contingency Reserve is already being used) Proposed by SDT: Refer to project page or NERC Glossary of Terms Suggested: Reporting ACE: Duke Energy is unsure why the SDT needs to include Reporting ACE as a revised definition in the proposed BAL-002-2 standard. This same definition has already been approved by the BOT and is in the NERC Glossary of Terms with no FERC Approval Date.
Group
Kansas City Power & Light
Brett Holland
Agree
SPP - Robert Rhodes
Individual
Texas Reliability Entity
Texas Reliability Entity
In R2, we feel that the five hours grace period for failing to maintain sufficient Contingency Reserves is too long, especially since Contingency Event Recovery Periods and EEAs are excluded. We recommend that there should be no grace period, and that the VSLs can be used to apply higher penalties for longer violations: 0-3 hours for lower VSL, 3-5 for moderate VSL, 5-10 for high VSL, and >10 for severe VSL.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Applicability Section: 4.1.1 needs clarification. It is unclear what "not in active status" means. Specifically, it is unclear whether a BA may be in "active status" by simply being under an RSG agreement and governing rules. It is unclear whether a BA not choosing to call on RSG assistance for any single Balancing Contingency Event (whether Reportable or not) would be considered "not in active status." This makes R2 unclear as to whether and when the BA is the Responsible Entity, what MSSC and reporting threshold would apply, or whether the 5-hour quarterly clock applies to the BA but not the RSG. Suggested language: A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority cannot rely upon the Reserve Sharing Group under the applicable agreement or governing rules for the Reserve Sharing Group. Rather than prescribe the commercial arrangements between members of a RSG, the above language respects whatever arrangements RSG members have put in place recognizing that these arrangements must enable the group and its members to remain in compliance with all applicable requirements. In R1, the added language "prior to that value of Reporting ACE" is confusing. It is unclear how a Balancing Contingency Event can be both subsequent and prior to a value of Reporting Ace. PPL cannot suggest a solution as we don't understand the intent of the added language. In R2, the calculation/evaluation of the 5 hour/quarter "exception clock" needs explanation. It is unclear whether a single EMS scan, where Contingency Reserve is calculated at less than MSSC, counts as an hour. It is unclear whether it is evaluated as the average, mean or median of the Contingency Reserves held for a Clock Hour. M2 specifies a Clock Hour as the time increment to be used – Clock Hour should also be stated in R2. PPL suggests that the 5-hour exception clock be based on the Clock Hour average amount of Contingency Reserves held by the Responsible Entity (BA or RSG) for the calendar quarter. As the proposed standard is significantly different from the historical/existing DCS, a draft RSAW should be provided so Responsible Entities can have an indication of how compliance will be evaluated.
Individual
Si Truc PHAN
Hydro-Québec TransÉnergie

We believe that this new draft is an improvement to the actual standard. However, there are three comments that we think should be considered in order to improve the actual. First, the Balancing Contingency Event definition uses the terminology “Any single event…” where the Most Severe Single Contingency definition uses the terminology “…due to a single contingency…” Hydro-Quebec TransÉnergie believes there is no difference between these two terminologies. In order to reduce the risk of misinterpretation, we recommend to be consistent in the definitions. Second, some contingencies occur within the Quebec Interconnection where generation is loss as well as load at the same time. For example, there are contingencies where 1900 MW of generation is loss and 1600 MW of DC converters at the same time which result in the net loss for the BA/Interconnection of 300 MW. The result causes only a small ACE change under the Reportable Balancing Contingency Event threshold. In addition, the 1600 MW of DC converter loss would probably be reported by another entity as a DCS due to a loss of an import. For this reason, Hydro-Quebec TransÉnergie suggests that the Balancing Contingency Event and the Reportable Balancing Contingency Event definitions would be more accurate if they would include the notion of net loss for the BA instead of only the generator MW output. Finally, as for the Reportable Balancing Contingency Event threshold, we feel that the 500 MW threshold for the Quebec Interconnection should be revised to 800MW. The actual threshold is set at 80% of MSSC which corresponds generally around 800 MW. This value already traps events that are significant for the Interconnection and truly measures events where contingency reserve is being deployed by operator actions. A too low threshold might capture events that are recovered with frequency response and AGC action, which are deployed quickly after the event since we are in a single BA Interconnection. We believe that the proposed threshold in the draft will increase the reporting without any improvement in measuring contingency reserve deployment. We would like to thank the SDT in advance for considering these comments.
Individual
Robert Blohm
Keen Resources Ltd.
Per my comments in the prior round, "Contingency Reserve" as here defined is a muddle because it includes the Frequency Responsive reserve deployed to first-respond to a Contingency Event. In fact, proper operation requires that properly-defined Contingency Reserve ultimately replace that Frequency Responsive Reserve deployed, as well as replace Regulating Reserve deployed in the interim, so that Regulating Reserve may be freed to respond to normal operating variability. Reserve needs to be defined by the physical nature of the reserve, not by any temporary use to which the reserve may be put. A more immediate solution to the unclarity is to rename the term here defined as "Reserve Used for Contingencies" rather than "Contingency Reserve" whose meaning would be more like reserve "assigned" to contingencies, just like Frequency Responsive Reserve is assigned to quickly arresting and holding frequency change. Replace in R1, in 2 places, "prior to THAT value of Reporting ACE" by "prior to, OR WHEN, ATTAINING THE MOST POSITIVE value of reporting ACE" These changes also need to be made in the Background Document's restatement of R1. In R2 VSLs, in 3 places, "less than or equal to" violates the rules of grammar and should be replaced by "no more than". In the first two bullets on page 7 of the Background Document, to be consistent with the Standard's R1, 1. the words "occurring before or when attaining the most positive Recording ACE" need to be inserted after the words "subsequent event, if any," and 2. the words "before or when attaining the most positive Recording ACE" need to be inserted after the words "subsequent events occurring". In the Background Document formulas the definition of SUM_SUBSQ requires appending "and before or when attaining the most positive Reporting ACE during that period" to make it consistent with the standard's R1. The formulas in the Background document are not in the standard mathematical form used in all other NERC standards and documents just because the CR Form 1 in which they are also entered is in Excel format that does not allow for entry of standard mathematical notation. This technical shortcoming in a spreadsheet calculation form should not impair the explanatory clarity of the Background Document where standard uniform mathematical notation should be the governing form of the standard, even if the CR Form 1 needs to convert it into machine-language computerese in order to repeat the explanation already given in the Background document. For replacement in the Background Document I provide at this link http://www.blohm.cnc.net/BAL002formulas the standard mathematical form of these formulas because this comment form does not allow the entry of mathematical notation (in particular, subscripting). Grammar: on page 7 of the Background Document, paragraph 2, "entity(s)" should be "entity's". Formatting: at the bottom of page 7, 1st paragraph of the "Compliance Calculation" section, two of the three lines should not be indented. Replacement in the current CR Form 1 spreadsheet of the word "claimed" by the word "included" on lines 40 and 41 of the Instructions tab is intended presumably to remove the optionality of recognizing subsequent events during the recovery period, and to be consistent with the requirement in the Standard's R1 of recognizing "all" the events before the most positive ACE and none after, for purposes of discounting the recovery requirement. If so, I support the consistency.
Individual
Brian Shanahan
National Grid Transmission Operations
Agree
We support the NPCC RSC's comments on this Standard.
Individual
Howard Illian
Energy Mark, Inc.
None
Individual

David Jendras
Ameren
Agree
We are generally supportive of the SERC OC Review Group Comments for BAL-002-2.
Individual
Catherine Wesley1
PJM Interconnection
General Comments We appreciate the opportunity to comment and the work the drafting team has contributed to this effort. We have concerns with some of the changes proposed to BAL-002 absent demonstrated need, particularly when the changes were not proposed in the team's SAR nor directed in Order No. 693. The SAR for the drafting team was basically to clean up the clutter in the standard and address Order No 693 directives. The only two true requirements in the standard are to recover from reportable events in 15 minutes and replenish reserves 90 minutes thereafter. Beyond this, we recommend focusing on the intent of the 693 directives. The NERC Resources Subcommittee performed analysis when DCS was first developed and found that the average time to recover from large unit trips was roughly 15 minutes. Recent analysis for BAL-003 has found that all four Interconnections recover from large unit trips in about 5 minutes. Compared to where we were 10 years ago, performance has been stellar. BAL-002 is working quite well today. If the definition for a Reportable Balancing Contingency Event is approved, what happens to the current definition for a Reportable Disturbance in the NERC Glossary? Does the existence of these two definitions create confusion or ambiguity? Comments on R1 Complexity. There is no reasoning provided for the complexity added to the calculation. The current approach is well understood by the industry. The SAR does not discuss changing the measurement approach. Events > MSSC. We have concerns with the new performance calculation for events greater than the Most Severe Single Contingency (MSSC). First, it appears the calculation would not work if the generators that were lost were the units carrying the Balancing Authority's reserves. Our second concern is that this proposed change may likely negatively impact reliability. It appears that the drafting team is attempting to put a measure on events > MSSC to ensure a Balancing Authority responds quickly to large events. While laudable in concept, multi-contingent events are typically associated with something wider happening on the transmission system. The priority for operators when something major occurs is transmission security rather than rushing to achieve a zero ACE. It should be remembered there are protective backstops in place absent this proposed change: • The IROL standards still require operators to take whatever action is necessary to prevent cascading with the next contingency, to include shedding load or redispatch. • The new BAL-001 standard will require the Balancing Authority to take action within 30 minutes to get frequency back within acceptable bounds. • The Energy Emergency Alert process still exists to address any reserve shortfall. Implementing a requirement that causes a knee-jerk ramping of all generation following a multi-contingent event may likely exacerbate congestion. With the recent approval of BAL-001-2 and future implementation of BAAL we question the appropriateness of requiring a BA to continue to drive their individual ACE higher under this standard after Interconnection frequency has already returned to schedule. This scenario would not be in the best interest of Interconnection reliability and respectfully suggest the SDT consider language that considers the contingent BA's recovery period satisfied when Interconnection frequency returns to scheduled frequency. Reporting. We support the current process whereby events > MSSC are reported. We have no problem with the report form asking for additional data for events > MSSC that are used in the Events Analysis and Reliability Assessment and Performance Analysis (RAPA) processes, but believe it is a mistake to add a performance expectation for events > MSSC. The preamble of the original Operating Manual on which we have built our standards outlined a premise that we operate to N-1 and make best efforts to protect the system for events greater than this. All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages. DCS performance is calculated and reported to the RRO on a quarterly basis. R1.1 states that CR Form 1 is the exclusive 'reporting form' but Measure 1 states it is to be maintained and provided upon request. R1.1 adds complexity and confusion to the reporting process. If CR Form 1 is to be used only for reporting a violation to NERC then this needs to be clarified in the requirement to avoid misinterpretation and confusion regarding NERC reporting versus RRO reporting. Comments on R2 This requirement proposes another major change to what is a superior approach of performance-based standards. This requirement will also likely have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). We believe the addition of a commodity measure will have unintended consequences. BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. Reserves should be used when there is a reliability need that may or may not be caused by the loss of a resource. This requirement encourages BA's to withhold deployment of contingency reserves except for DCS reportable disturbances. For example: • If a BA's ACE is dragging into the top of the hour, along with Interconnection frequency, due to schedule changes and slow unit response, this requirement incentivizes the BA to withhold deploying reserves. • If a BA is approaching an IROL that could be mitigated by deploying contingency reserves, this requirement penalizes the BA for doing so, even though the result would benefit Interconnection reliability. • A BA would be penalized for using it's contingency reserves to provide assistance to a neighboring BA(s) if no reserve sharing agreement exists. This will likely have an adverse impact on Interconnection cooperation and reliability. • R2 does not take into account the comingled relationship between contingency reserves and frequency responsive reserves. For example, a BA could maintain additional synchronized reserves to cover both the MSSC and FRO requirements set forth in BAL-002 & BAL-003 as long as sufficient generating units have governors in service with proper control settings. During a frequency event

outside their balancing area, a BA could be penalized under the hourly average terms of BAL-002 R2 if they provide frequency response above & beyond their FRO that causes contingency reserves to go below MSSC. Essentially, this requirement could encourage BA's to limit frequency responsive reserves. BAs that don't withhold contingency reserves for non-DCS events will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The standard provides no clear definition on how contingency reserves are measured. Does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Finally, are the hours referenced in the standard clock-hours, any contiguous 60 minute period, or the total minutes in a quarter divided by 60? If we agreed with R2, which we do not, we believe that this 'quarterly forgiveness' is confusing, has not been adequately defined, and could easily be misinterpreted. Proposed Solutions The SAR for the drafting team was basically to clean up the clutter in the standard and address Order No 693 directives. The only two true requirements in the standard are to recover from reportable events in 15 minutes and replenish reserves 90 minutes thereafter. These should be the basis of this standard. We recommend the two core requirements be: R1. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall activate sufficient Contingency Reserve to comply with the DCS. Events > than MSSC are reported, but do not factor into the compliance calculation. R2. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall replenish its reserves within 105 minutes of the onset of the Reportable Event. To provide clarity, the compliance section of the standard should describe the reporting approach for events > MSSC. The "Reserve Guidelines" document should be expanded to explain that BAs are expected to make best efforts to recover from events > MSSC, but that transmission security takes precedence. Either the Reserve Guidelines document, the compliance section of the standard, or an appendix to the standard should include the reporting form for DCS. Alternatively, the drafting team could create the report in spreadsheet form. The form should include the basis of the MSSC and clarify that the form is to be used for NERC reporting and under what conditions; periodic or only upon non-compliance. The sizes of the Reportable Events for the Interconnections proposed by the drafting team are acceptable and meet the intent of one of the 693 directives.
Individual
Denise M. Lietz
Puget Sound Energy
In section A of the definition of Balancing Contingency Event, the word "Loss" should not be capitalized since it is not a defined term. In the definition of Most Severe Single Contingency, the drafting team should capitalize "contingency" where it is used in the phrase "due to a single contingency". "Contingency" is defined in the NERC Glossary and it is confusing to use an undefined version of a defined term, because that use leads to the question about how this version of "contingency" differs from the defined version. In addition, the defined term looks appropriate to use in this context. The last full sentence of the definition of "Reportable Balancing Contingency Event" does not indicate who can reduce the 80% threshold. It should instead read "A Responsible Entity may reduce the 80% threshold upon written notification to the Regional Entity." The first sentence of R1 should require recovery of "Reporting ACE" (right now it just applies to "ACE"). The use of the phrase "prior to that value of Reporting ACE" in the two bullets of R1 that address subsequent events is confusing and ambiguous. It is difficult to suggest alternative language without understanding the phrase's intended purpose. Including the language about energy emergencies in the applicability section and in the requirements has the potential to create ambiguity in the application of the standard. The better approach is to deal with this matter in the applicability section alone. The Severe VSL for requirement R1 leaves a situation where there was no recovery at all out of the equation entirely. This VSL could instead read "The Responsible Entity failed to provide any of the required recovery or recovered partially ... but recovered 70% or less of required recovery."
Group
ISO-RTO Council Standards Review Committee
Terry Bilke
General Comments We appreciate the opportunity to comment and the work the drafting team has contributed to this effort. We have concerns with some of the changes proposed to BAL-002 absent demonstrated need, particularly when the changes were not proposed in the team's SAR nor directed in Order No. 693. The SAR for the drafting team was basically to clean up the V0 clutter in the standard and address Order No 693 directives. The only two true requirements in the V0 standard are to recover from reportable events in 15 minutes and replenish reserves 90 minutes thereafter. Beyond this, we recommend focusing on the intent of the 693 directives. The NERC Resources Subcommittee performed analysis when DCS was first developed and found that the average time to recover from large unit trips was roughly 15 minutes. Recent analysis for BAL-003 has found that all four Interconnections recover from large unit trips in about 5 minutes. Compared to where we were 10 years ago, performance has been stellar. BAL-002 is working quite well today. We don't agree with the use of this standard to define terms not directly needed in the standard (e.g. Reporting ACE). We disagree with the new definition of Contingency Reserve as it provides no guidance on how to objectively measure reserves. Definitions Reserve Sharing Reporting ACE. The proposed term Reserve Sharing Group Reporting ACE is not needed as it is not referenced in the standard and serves no purpose. Pre-Reporting Contingency Event ACE Value. The measurement process used to date has been effective. We see no reason to add this level of complexity. Comments on R1 Complexity. There is no reasoning provided for the complexity added to the calculation. The current approach is well understood by the industry. The SAR does not discuss changing the measurement approach. Events > MSSC. We have concerns with the

new performance calculation for events greater than the Most Severe Single Contingency (MSSC). First, it appears the calculation would not work if the generators that were lost were the units carrying the Balancing Authority's reserves. Our second concern is that this proposed change may likely negatively impact reliability. It appears that the drafting team is attempting to put a measure on events > MSSC to ensure a Balancing Authority responds quickly to large events. While laudable in concept, multi-contingent events are typically associated with something wider happening on the transmission system. The priority for operators when something major occurs is transmission security rather than rushing to achieve a zero ACE. It should be remembered there are protective backstops in place absent this proposed change: • The IROL standards still require operators to take whatever action is necessary to prevent cascading with the next contingency, to include shedding load or redispatch. • The new BAL-001 standard will require the Balancing Authority to take action within 30 minutes to get frequency back within acceptable bounds. • The Energy Emergency Alert process still exists to address any reserve shortfall. Implementing a requirement that causes a knee-jerk ramping of all generation following a multi-contingent event may likely exacerbate congestion. We support the current process whereby events > MSSC are reported. We have no problem with the report form asking for additional data for events > MSSC that are used in the Events Analysis and Reliability Assessment and Performance Analysis (RAPA) processes, but believe it is a mistake to add a performance expectation for events > MSSC. The preamble of the original Operating Manual on which we have built our standards outlined a premise that we operate to N-1 and make best efforts to protect the system for events greater than this. Here is the text from the Operating Manual. All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages. Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is no different than CPS1 and CPS2 whose performance is based on annual and monthly calculations. There have been no reliability issues that point to the need for making the DCS an event-by-event standard as is now proposed. We believe this proposed change will lead to changes in how Reserve Sharing Groups will select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward for no defined need. ACE Definition. R1 requires the Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least:…… ACE is currently defined as: "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 Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection." We thus interpret "its ACE" in Requirement R1 to mean a BA's ACE unless the RSG is explicitly mentioned in the requirement. If this is to be interpreted as the Responsible Entity's ACE which also includes the RSG since it is included in the Applicability Section, then a term Reserve Sharing Group ACE will need to be defined, or some explicit language be added to R1 to achieve the purpose that the SDT suggests in its response to our comments. Comments on R2 This requirement proposes another major change to what is a superior approach of performance-based standards. This requirement will also likely have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). We believe the addition of a commodity measure will have unintended consequences. The first unintended consequence is that BAs are encouraged by this requirement never to deploy their contingency reserves except for DCS-reportable events. BAs whose ACE is extremely negative for other reasons would be reluctant to deploy their contingency reserves because the timer would start ticking on the "available hours" clock. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. The standard provides no clear definition on how contingency reserves are measured. Does it include all generation headroom available in 10 minutes? In 15 minutes? What about resources that are also providing AGC? Does their instantaneous headroom count? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Finally, are the hours referenced in the standard clock-hours, any contiguous 60 minute period, or the total minutes in a quarter divided by 60? Proposed Solutions We recommend the two core requirements in the existing BAL-002 be retained with modification: R1. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall activate sufficient Contingency Reserve to comply with the DCS. Events > than MSSC are reported, but do not factor into the compliance calculation. R2. Except when experiencing an Energy Emergency Alert Level 2 or Level 3, a Balancing Authority or Reserve Sharing Group experiencing a Reportable Event less than or equal to its MSSC shall replenish its reserves within 105 minutes of the onset of the Reportable Event. We would be OK with an addition requirement that asks the BA to perform an assessment of its next day and real time reserve targets and the basis of its MSSC and that the BA provide this assessment to its Operators and its Reliability Coordinator. The assessment should be done each calendar year or within a month following an event > MSSC. To provide clarity, the compliance section of the standard should describe the reporting approach for events > MSSC. The "Reserve Guidelines" document should be expanded to explain that BAs are expected to make best efforts to recover from events > MSSC, but that transmission security takes precedence. Either the Reserve Guidelines document, the compliance section of the standard, or an appendix to the standard should include the reporting form for DCS. Alternatively, the drafting team could create the report in spreadsheet form. The reporting form should be similar to what is used today. The form should include the basis of the MSSC. The sizes of the Reportable Events for the Interconnections proposed by the drafting team are acceptable and meet the intent of one of the 693 directives. We believe it is acceptable to put something in the compliance section of the standard that notes if the same event > than MSSC occurs within 3 years, the BA should be held to the DCS for that contingency until it demonstrates the triggering mechanism has been mitigated. We agree with the current direction of the team to address the 693 directive to develop a "continent-wide contingency reserve policy" via the "Reserve Guidelines" document. Beyond what is mentioned above, the

document should provide guidance on how the BA assesses the necessary amount of reserves as well as provide simple definitions of the different types of reserves (in particular for this standard, contingency reserves and replacement reserves). Once these terms are defined and commented on by the Industry in the document, NERC should add these types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data” with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We believe there would be significant reliability value in giving RCs visibility of the current state of Contingency Reserves (something callable in 10 minutes, fully deployed in 15 minutes and sustainable for at least 90 minutes) and Replacement Reserves (something callable in 90 minutes and sustainable for say 4 hours). This would directly contribute to reliability by providing objective information to BAs and RCs in managing Energy Emergency Alerts.
Individual
Richard Vine
California Independent System Operator
The proposed standard would require the California ISO to treat a loss of MW output greater than or equal to 500 MW as a Reportable Balancing Contingency Event resulting in dispatch of reserves to meet DCS recovery time limits. Currently, the ISO is only required to dispatch reserves for DCS events greater than 80 percent of the Most Severe Single Contingency, or about 900 MW. There does not appear to be any technical justification for this significant reduction in reporting/action threshold which will result in the unnecessary deployment of contingency reserves on a more frequent basis.
Group
Southern Company: Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Agree
SERC OC Standards Review Group
Group
Bureau of Reclamation
Erika Doot
The Bureau of Reclamation supports the proposed standard.
Group
Bonneville Power Administration
Jamison Dye
BPA concurs with the current draft of BAL-002-2 with no comments or concerns.
Individual
Kathleen Goodman
ISO New England Inc.
Agree
IRC SRC

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Balancing Authority Reliability-based Controls: Reserves (BAL-002-2)

An Additional Ballot and Non-Binding Poll is now open through September 16, 2013

Now Available

An additional ballot for **BAL-002-2- Contingency Reserve for Recovery from a Balancing Contingency Event** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now open **through 8 p.m. Eastern on Monday, September 16, 2013.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

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 final ballot.

Standards Development 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 Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **BAL-002-2- Contingency Reserve for Recovery from a Balancing Contingency Event** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **through 8 p.m. Eastern on Monday, September 16, 2013.**

Voting statistics for the additional ballot are listed below, and the Ballot Results page provides a link to the detailed results. This standard achieved a quorum but did not receive sufficient affirmative votes for approval.

Approval	Non-binding Poll Results
Quorum: 76.15% Approval: 58.23%	Quorum: 75.69% Supportive Opinions: 59.66%

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 standard. The standard will then proceed to an additional comment period and ballot.

Standards Development 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.

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-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-002-2 Ballot_2 Sept 2013
Ballot Period:	9/6/2013 - 9/17/2013
Ballot Type:	Additional Ballot
Total # Votes:	265
Total Ballot Pool:	348
Quorum:	**76.15 % The Quorum has been reached**
Weighted Segment Vote:	58.23 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	31	0.492	32	0.508	0	7	20
2 - Segment 2	10	0.8	3	0.3	5	0.5	0	1	1
3 - Segment 3	79	1	30	0.517	28	0.483	0	6	15
4 - Segment 4	24	1	12	0.75	4	0.25	0	2	6
5 - Segment 5	73	1	26	0.531	23	0.469	0	5	19
6 - Segment 6	53	1	18	0.486	19	0.514	0	1	15
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	6	0.2	2	0.2	0	0	0	0	4
9 - Segment 9	3	0.1	1	0.1	0	0	0	0	2
10 - Segment 10	8	0.8	6	0.6	2	0.2	0	0	0
Totals	**348**	**7**	**130**	**4.076**	**113**	**2.924**	**0**	**22**	**83**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)

1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - Xcel Energy - (MRO-NSRF)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO comments)
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	Abstain	
1	Platte River Power Authority	John C. Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM comments)
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
				SUPPORTS THIRD PARTY

1	Salt River Project	Robert Kondziolka	Negative	COMMENTS - (Salt River Project)
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	COMMENT RECEIVED
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
2	Alberta Electric System Operator	Ken A Gardner	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New Brunswick System Operator	Alden Briggs	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC & IRC/SRC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	COMMENT RECEIVED
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris		

3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
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		
3	ComEd	John Bee	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting NPCC comments)
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	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Gulf Power Company	Paul C Caldwell	Negative	COMMENT RECEIVED
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	COMMENT RECEIVED

3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - Xcel Energy - (MRO NERC Standards Review Forum (NSRF))
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's comments)
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide comments)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SPP)
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland @ Xcel Energy)
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	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Team)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	COMMENT RECEIVED
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	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (See MISO's comments)
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
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	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	

5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide group comments)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Negative	COMMENT RECEIVED
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES(MRO & NSRF) - (MRO & NSRF)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - XCEL ENERGY - (MRO NSRF)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel		

5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (adopting comments of Public Service Enterprise Group)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
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		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP & Xcel Energy)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide group comments)
6	Constellation Energy Commodities Group	David J Carlson	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Comments)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
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		
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik		
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO Comments)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support SPP's Comments)
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support Xcel Energy's comments)
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
				SUPPORTS THIRD PARTY

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENTS - (PSEG will submit comments supporting PJM's comments)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
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		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	COMMENT RECEIVED
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz		
8		Edward C Stein		
8		Robert Blohm	Affirmative	
8	Debra R Warner	Debra R Warner		
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
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	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Carter B Edge	Negative	SUPPORTS THIRD PARTY COMMENTS - SERC OC Review Group
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

Non-binding Poll Results

Project 2010-14.1 BAL-002-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-14.1 BARC BAL-002-2 Non-binding Poll Sept 2013_sc_1
Poll Period:	9/6/2013 - 9/18/2013
Total # Opinions:	246
Total Ballot Pool:	325
Summary Results:	75.69% of those who registered to participate provided an opinion or an abstention; 59.66% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	

1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Commnets)
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	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title of PPL NERC Registered Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (AECI)
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		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	COMMENT RECEIVED
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
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	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
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	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	COMMENT RECEIVED
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick		
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	

3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting NPCC comments)
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	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Gulf Power Company	Paul C Caldwell	Negative	COMMENT RECEIVED
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
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	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Associated Electric Cooperative Inc)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	COMMENT RECEIVED
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC comments)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's comments)
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide comments)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	

3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
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	Affirmative	
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	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
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	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	

5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments previously submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide group comments)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - ACES(MRO & NSRF) - (MRO & NSRF)

5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Lakeland Electric	James M Howard	Affirmative	
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		
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
5	Oglethorpe Power Corporation	Bernard Johnson	Abstain	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
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	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	

5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
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		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP & Xcel Energy)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's region-wide group comments)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Comments)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (FirstEnergy)
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		
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik		
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO Comments)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support SPP's Comments)
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support Xcel Energy's comments)
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)

6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	COMMENT RECEIVED
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz		
8		Edward C Stein		
8		Robert Blohm	Affirmative	
8	Debra R Warner	Debra R Warner		
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	Abstain	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
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	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

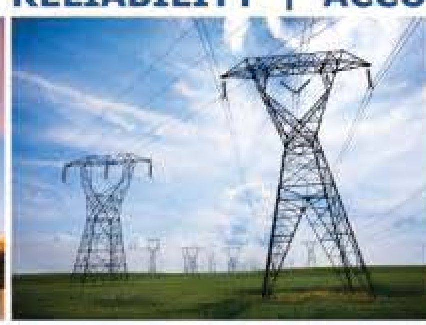
Consideration of Comments Summary

Project 2010-14.1 BARC – Reserves
BAL-002-2

October 15, 2013

RELIABILITY | ACCOUNTABILITY



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Suite 600, North Tower
Atlanta, GA 30326

Introduction

The Project 2010-14.1 Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-002-2 The standard was posted for a 45-day formal comment period from August 2, 2013 through September 18, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 35 sets of responses, including comments from approximately 100 different people from approximately 66 companies representing 7 of the 10 Industry Segments..

All comments submitted may be reviewed in their original format on the 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 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

Consideration of Comments

Purpose

The BARC Standard Drafting Team (SDT) appreciates industry's comments on the BAL-002-2 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if an additional comment period and ballot are needed. The following pages are a summary of the comments received and how the SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer to discuss.

Standards Authorization Request (SAR)

A couple of commenters stated that the SDT was going beyond what was allowed within the current SAR. The SDT disagrees with these commenters as it is attempting to bring all of the compliance elements, some of which are presently located in the Additional Compliance section of the standard, into the requirements. The SDT also believes that the current draft of the standard is eliminating ambiguity within the present standard.

NERC Glossary Term "Reportable Balancing Contingency Event"

A few commenters believed that the definition was vague and ambiguous. The SDT agreed with the commenters and modified the definition to provide additional clarity.

Some commenters questioned the need for this term. The SDT is addressing a FERC directive to create a continent wide Contingency Reserve Policy. The SDT believes that the first step in creating this policy is to define what would constitute a reportable event. The SDT believes it is addressing the directive by defining what constitutes a reportable event.

A small number of commenters expressed confusion about when a Balancing Contingency Event could become a Reportable Balancing Contingency Event. The SDT addressed this concern within the definition of a Reportable Balancing Contingency Event, with the phrase "occurring within a one minute interval based on EMS scan rate data." For example, if a Balancing Authority's (BA) Most Severe Single Contingency (MSSC) is 500 MW, then 80% of 500 MW yields a 400 MW change that must be observed within a sliding one minute interval in the output of the resource lost in order to qualify as a Reportable Balancing Contingency Event. When the output of the resource lost meets this criterion, the first occurrence of a decline in the lost resource's output observed within the EMS scan rate data within that sliding one minute interval demarcates the start of the event.

Definitions

A couple of commenters were concerned that the definition for Contingency Event did not provide for any guidance on how to measure reserves. The SDT does not believe that the definition should contain any reference as to how to measure the reserves, rather the definition should only provide details on *what* may constitute Contingency Reserve. This approach allows entities flexibility to account for entity-specific circumstances.

Some commenters stated that they did not believe that Balancing Contingency Event needed to be defined and disagreed with the statement that the current version of the standard is "broad and could be interpreted in various manners." They also stated that there have not been any reliability issues or events that justify the need for this clarification. The SDT disagrees with their comment and points to the request made by the Northwest Power Pool for an interpretation of BAL-002-1 currently pending at FERC in Docket No. RM-13-6-000. The interpretation was requested to provide clarity as to what constituted a Disturbance Control Standard (DCS) event and if a BA was to be held compliant for an event greater than its MSSC.

One commenter felt that there was the possibility for misinterpretation between the use of the terms “event” and “contingency” within the definitions for Balancing Contingency Event and Reportable Balancing Contingency Event. The SDT believes that an event could be composed of several contingencies but a contingency could not be composed of several events.

Applicability Section

A couple of commenters identified an error in the body of the applicability section with the use of the term event. The SDT changed the term “event” to “Event”, which is a defined term included in the Glossary of Terms Used in NERC Reliability Standards so that the term is now shown as “Reportable Balancing Contingency Event” to correct the error.

Some commenters questioned the need for including language that defined when a BA was not participating as a member of a Reserve Sharing Group (RSG). The SDT is aware of RSGs that allow a BA to participate as a member of the RSG or to respond to an event without activation of the RSG. Since some RSGs allow for this to occur, the SDT feels that the language is appropriate and should be included in the applicability section.

Effective Date

The SDT modified the effective date language to use the current language provided by NERC legal.

Energy Emergency Alert Level 2 or Level 3

A couple of commenters disagreed with the SDT using the terms Energy Emergency Alert Level 2 or Level 3 since these terms are not in the NERC Glossary of Terms and only defined within the EOP-002 standard. The SDT is attempting to correct the present inconsistency between BAL-002 and EOP-002. The SDT has identified the problem that if a BA is operating under either an Energy Emergency Alert Level 2 or Level 3 it would have deployed its reserves but would still be held compliant with the present BAL-002-1. The SDT has also discussed this problem with the NERC SDT that is presently reviewing the EOP standards. They will be evaluating whether or not to include these terms within the NERC Glossary with the BARC SDT’s recommendation that they should be included.

Requirement R1

The SDT made some minor clarifying modifications to the requirement.

A few commenters said that the language in Requirement R1 was too complex and hard to understand. The SDT is correcting problems inherent in the current standard, which erroneously establish some requirements within the compliance elements of the standard. By moving the requirements language from the compliance elements into the requirements, the SDT believes that it more properly addresses instances regarding events that may be greater than MSSC. The SDT has also provided CR Form 1 to assist BAs in calculating its compliance with a Reportable Balancing Contingency Event.

Some of the commenters felt that there should only be two requirements: 1) a BA must activate sufficient Contingency Reserve to comply with DCS; and, 2) a BA must recover within 105 minutes. The SDT disagreed with the commenters; the SDT believes that the suggested requirements do not cover all situations that could arise and leaves too many gaps which creates ambiguity.

A couple of commenters were confused as to when they would have to use CR Form 1 to document events. The SDT modified Requirement R1 part 1.1 to clearly state that all Reportable Balancing Contingency Events are required to be documented using CR Form 1. The CR Form 1 is mentioned in the requirement and will be attached to the standard, therefore making the use of the form enforceable.

The SDT added Requirement R1 part 1.3 to clearly identify that a BA would not be held compliant with Requirement R1 when its Reportable Balancing Contingency Event exceeded its MSSC during the Contingency Event Recovery Period or its Contingency Reserve Restoration Period.

One commenter stated that the draft standard was requiring deployment of reserves for any and all events. The SDT disagrees with the commenters concern. The current draft of the standard does not require the deployment of reserve for anything other than a Reportable Balancing Contingency Event. The SDT has added language in the Additional Compliance section that allows a BA to deploy reserves for events other than a Reportable Balancing Contingency Event but does not require this to be done.

Requirement R2

Several commenters did not believe that Requirement R2 was necessary. The SDT disagrees and believes the requirement is necessary for reliability and to meet the approach for the FERC directive. The current standard (Requirement R3 part 3.1) requires a BA or RSG to maintain Contingency Reserve at least equal to its MSSC.

A couple of commenters disagreed with allowing a BA's Contingency Reserve to drop below its MSSC for five hours per quarter. A few other commenters stated that they were unsure as to how to track the five hour exemption. Although the SDT felt that here were times when a BA could legitimately be under its MSSC, the SDT could not develop a sufficient argument to allow a BA to be deficient and not have its MSSC at all times other than during the times when the Contingency Reserve was being deployed or when the BA is operating during the Contingency Event Recovery Period, the Contingency Reserve Restoration Period, the Energy Emergency Alert Level 2, or the Energy Emergency Alert Level 3 given that the present standard does not allow for any such exemption.

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For clarity, The SDT modified the requirement to clearly state that the Contingency Reserve would be averaged over the Clock Hour to determine compliance.

Measure M2

The SDT added language to the measure for Requirement R2 to identify when data would be excluded from the calculation of Contingency Reserve.

Violation Severity Levels (VSLs)

There were comments regarding concerns with the VSLs. All VSLs have been reviewed and modified as necessary to ensure proper alignment with the requirements.

The SDT felt that the VSL for Requirement R2 should not be an "all or nothing" type of VSL. The SDT modified the VSL to allow for differing severity levels of non-compliance. The SDT chose the levels to be consistent with the levels of non-compliance used by the WECC in their currently filed regional BAL-002 standard pending acceptance by FERC.

Quarterly Compliance

The only DCS quarterly performance reporting is for Requirement 3 of presently existing Reliability Standard BAL-002-1, which says "Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS." There are 2 additional requirements, R4 and R5, which have immediate compliance implications. Requirement 4 states "A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances." This is an immediate measure of a BA's ability to return its Area Control Error (ACE) to pre-disturbance ACE or zero depending on the pre-disturbance. Requirement 5 states "Each Reserve Sharing Group shall comply with the DCS." A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members, and makes no mention of quarterly compliance. The same is true for Requirement 4; therefore, it is also subject to immediate compliance.

The Disturbance Recovery Criterion is calculated for each event and reported on a quarterly basis; however, such events are relatively rare and there may be one or less such events in a given quarter. Many of the significant events in NERC which involved unit tripping have resulted in the responsible entity paying a fine for failure to comply with BAL-002. Therefore it is necessary to clarify that DCS compliance is based on an event-by-event basis and not on a quarterly basis. DCS recovery is not a long term measure and a quarterly measure could send the wrong signal to the responsible entity.

The newly proposed BAL-002 no longer includes a provision for increasing the amount of contingency reserves as a part of the penalty for non-compliance. In fact, the increasing of contingency reserves is not now part of what NERC would impose as a penalty. In addition, the increases in contingency reserves associated with non-compliance most likely would result in a much bigger monetary consequence than the sanction/fine that would be imposed by NERC. Since increasing Contingency Reserves is no longer part of the penalty, using a quarterly measure to determine an average failure makes little sense. As soon as a responsible entity fails to comply with DCS requirements for an event, they will fail for the quarter. If that failure were to occur early in the quarter, there could be exposure to additional penalties since it may be non-compliant for up to 90 days since the failure before the determination of the quarterly measure is made.

New NERC standards typically use a report by exception instead of continuous reporting scheme. The proposed BAL-002 does not include a reporting requirement. The SDT provides a statement of the required performance (what is required) and the CR Form 1 to use in determining compliance. If a responsible entity determines it was non-compliant for a reportable event, they are expected to self-report, similar to any other discovery of non-compliance. A failure to self-report could result in the non-compliance being discovered at the next audit of the entity, with exposure to many days of non-compliance.

Background Document

The SDT modified the BAL-002-2 Background Document to provide rationale for excluding events greater than a BA's MSSC.

Reliability Standard Audit Worksheet (RSAW)

The SDT received comments requesting a Reliability Standards Audit Worksheet (RSAW). The SDT will be involved with the drafting of a new RSAW to ensure that the intent of the BAL-002-2 requirements are addressed properly. The SDT will work with the NERC Compliance staff in the development of a RSAW. This will provide a mechanism for the SDT to provide the necessary information for consistency between the standards language and the RSAW compliance tool.

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.
10. The third draft standard was posted for 45-day formal industry comment period and successive ballot from August 2, 2013 through September 16, 2013.

Proposed Action Plan and Description of Current Draft:

This is the fourth posting of the proposed standard. This proposed draft standard will be posted for a 45-day formal comment period and 10-day successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Fourth posting	October/November 2013

2. Successive Ballot	November/December 2013
3. Recirculation Ballot	January 2014
4. NERC BOT adoption.	February 2014

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 Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.

C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3 as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   Applicability is determined on an individual Reportable Balancing Contingency Event basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

   4.1. Balancing Authority

   4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.2. Reserve Sharing Group

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

   5.1. The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees' or as otherwise provided for in that jurisdiction.

B. Requirements

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and

- o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC,

Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative),
  - o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and
  - o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC.

1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency.

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1 and additional documentation of any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with Requirement R2.

If the recording of Contingency Reserve is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule (EEA 2 overlap, EEA 3 overlap, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered 70% or less of required recovery during the Contingency Event Recovery Period.
R2	The Responsible Entity had Contingency Reserve but the amount of Contingency Reserve was less	The Responsible Entity had Contingency Reserve but the amount of Contingency Reserve was less	The Responsible Entity had Contingency Reserve but the amount of Contingency Reserve was less	The Responsible Entity did not have Contingency Reserve that was equal to or greater than 70% of MSSC

	than 100% of MSSC but was greater than or equal to 90% of MSSC as averaged over the Clock Hour.	than 90% of MSSC but was greater than or equal to 80% of MSSC as averaged over the Clock Hour.	than 80% of MSSC but was greater than or equal to 70% of MSSC as averaged over the Clock Hour.	averaged over the Clock Hour.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
9. The draft standard was posted for 45-day formal industry comment period and initial ballot from March 12, 2013 through April 25, 2013.
10. The third draft standard was posted for 45-day formal industry comment period and successive ballot from August 2, 2013 through September 16, 2013.

Proposed Action Plan and Description of Current Draft:

This is the fourth posting of the proposed standard. This proposed draft standard will be posted for a 45-day formal comment period and 10-day successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Fourth posting	October/November 2013

2. Successive Ballot	November/December 2013
3. Recirculation Ballot	January 2014
4. NERC BOT adoption.	February 2014

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 Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden l~~L~~oss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less~~greater~~ than or equal to the ~~lesser amount of 80 percent of the~~ Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, ~~-~~or (ii) the amount listed below for the applicable Interconnection, and occurring within a ~~rolling~~ one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, t~~T~~he 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3 as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual Reportable Balancing Contingency E~~e~~vent basis, but this standard does not apply to a Responsible Entity during periods when the Responsible Entity is in Energy Emergency Alert Level 2 or Level 3.

4.1. Balancing Authority

4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.2. Reserve Sharing Group

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

5.1. The f~~F~~irst day of the first calendar quarter that is six months after~~beyond~~ the date that this standard is approved by applicable regulatory authorities~~,~~ or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become~~in those jurisdictions where regulatory approval is not required, the standard becomes~~ effective on the first day of the first calendar quarter that is six months after~~beyond~~ the date the~~is~~ standard is adopted~~approved~~ by the NERC Board of Trustees'~~,~~ or as otherwise provided for in that jurisdiction~~made effective pursuant to the laws applicable to such ERO governmental authorities~~.

B. Requirements

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):

  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and
  - f~~F~~urther reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC,

  Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative),
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and
  - f~~F~~urther reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC.

1.1. All Reportable Balancing Contingency Events will be documented using~~The required reporting form is~~ CR Form 1.

1.2. ~~This r~~Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency.

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity ~~and for an additional five hours during a given calendar quarter~~, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its

Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1 and additional documentation of any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.

M2. Each Responsible Entity shall have dated documentation that demonstrates its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance with Requirement R2.

If the recording of Contingency Reserve is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule (EEA 2 overlap, EEA 3 overlap, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level 2 or Level 3.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered ~~partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered~~ 70% or less of required recovery during the Contingency Event Recovery

				Period.
R2	~~In each calendar quarter, t~~The Responsible Entity had Contingency Reserve~~s~~ but the amount of Contingency Reserve was less than 100% of MSSC but was greater than or equal to 90% of MSSC as averaged over the Clock Hour~~its Contingency Reserve was deficient for more than 5 hours but less than or equal to 15 hours~~.	~~In each calendar quarter, t~~The Responsible Entity had Contingency Reserve~~s~~ but the amount of Contingency Reserve was less than 90% of MSSC but was greater than or equal to 80% of MSSC as averaged over the Clock Hour.~~its Contingency Reserve was deficient for more than 15 hours but less than or equal to 25 hours.~~	~~In each calendar quarter, t~~The Responsible Entity had Contingency Reserve~~s~~ but the amount of Contingency Reserve was less than 80% of MSSC but was greater than or equal to 70% of MSSC as averaged over the Clock Hour.~~its Contingency Reserve was deficient for more than 25 hours but less than or equal to 35 hours.~~	~~In each calendar quarter, t~~The Responsible Entity did not have~~had~~ Contingency Reserve that was equal to or greater than 70% of MSSC averaged over the Clock Hour~~s but its Contingency Reserve was deficient for more than 35 hours~~.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14,	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth	Errata

	2006	bullet.	
2		NERC BOT Adoption	Complete revision

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

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Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

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Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

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    a. Due to
        i. Unit tripping,
        ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
        iii. Sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

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Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The f~~F~~irst day of the first calendar quarter that is six months after~~beyond~~ the date that this standard is approved by applicable regulatory authorities~~,~~ or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become ~~in those jurisdictions where regulatory approval is not required, the standard becomes~~ effective on the first day of the first calendar quarter that is six months after~~beyond~~ the date the~~is~~ standard is adopted~~approved~~ by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction~~made pursuant to the laws applicable to such ERO governmental authorities~~.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event. Comments must be submitted using the electronic comment form by 8 p.m. **December 11, 2013.** If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

Background Information:
Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard.

- Modified the definition for a Reportable Balancing Contingency Event to provide additional clarity.
- Modified the effective date to use the most current NERC approved language.
- Modified Requirement R1 to provide additional clarity.
- Modified Requirement R1 to clearly state when CR Form 1 had to be used.
- Modified Requirement R1 by adding Requirement R1 part 1.3 to clearly identify that a BA would not be held compliant with Requirement R1 when its Reportable Balancing Contingency Event exceeded its MSSC during the Contingency Event Recovery Period or its Contingency Reserve Restoration Period
- Removed the 5 hour exemption from Requirement R2.
- Modified the measure for Requirement R2 to identify when data would be excluded from the calculation of Contingency Reserve.
- Modified the VSLs to align with the requirements.

- Modified the BAL-002-2 Background Document to provide rationale for excluding events greater than a BA's MSSC.

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. **Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.**

   Comments:

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BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

RELIABILITY | ACCOUNTABILITY

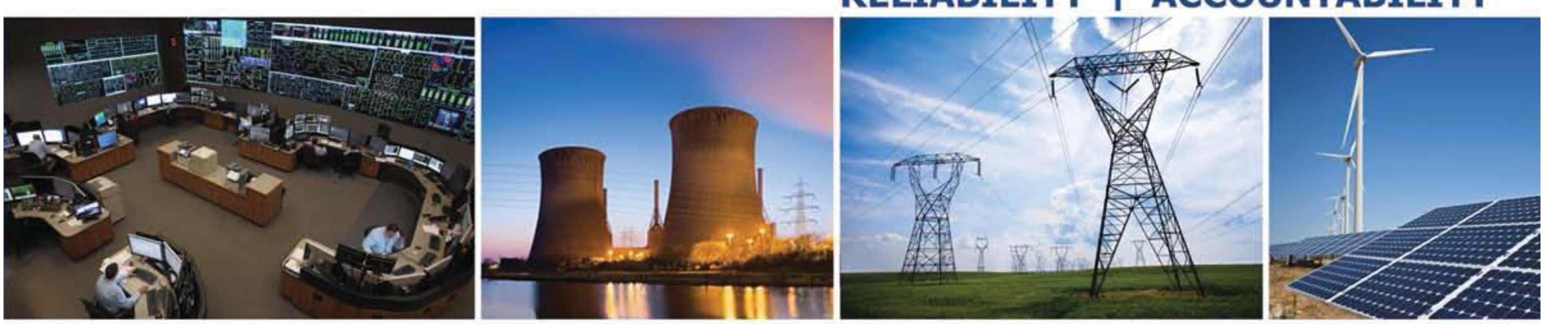

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Table of Contents

Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's most severe single contingency.

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question on who is the applicable entity and assures the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 solely a performance standard. The primary objective of BAL-002-2 is to assure the applicable

entity balances resources and demand and returns its Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. Rather, the combination of the recently passed BAL-001-2 standard, in which R2 requires operation within an ACE bandwidth based on interconnection frequency, TOP-007 and EOP-002, are much better at addressing issues when large events occur. The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL will allow the BA time to quickly evaluate the best course of action and then react in a reasonable manner. The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances that could cause transmission overloads if certain units (typically N-1-1 or greater) where lost and reserves responded. In addition, under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented. Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for and not any loss of resource that would exceed MSSC. Therefore, the definitions and requirements under BAL-002-2 exclude events greater than the MSSC. This will help ensure reliable operation, clarity of requirements and supports reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing contingency reserve definitions primarily focused on generation and not Demand Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complimented each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event, and without a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

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The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least:

- Zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and
  - further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC,

  , Or
- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative):
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and
  - Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC

1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of contingency reserve.

Additionally, R 1 is designed to assure the applicable entity must use reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the drafting team elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of the FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the required contingency reserve response and measured contingency reserve response are computed and compared as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.
- The measured contingency reserve response is equal to one of the following:
  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.

- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the required contingency reserve response is greater than zero,
    - And the measured contingency reserve response is greater than or equal to the required contingency reserve response, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
    - And the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
    - And the measured contingency reserve response is less than the required contingency reserve response but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((required contingency reserve response – measured contingency reserve response) / required contingency reserve response)).

The above computations can be expressed mathematically in the following 7 sequential steps, labeled as [1-7], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)

SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[2]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[3]**

If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 **[4]**

If REQ_CR_RESP is greater than 0, and,

MEAS_CR_RESP is greater than or equal to REQ_CR_RESP, then

COMPLIANCE = 100 **[5]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[6]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is greater than 0, and,

MEAS_CR_RESP is less than REQ_CR_RESP, then

COMPLIANCE = 100 * (1 – ((REQ_CR_RESP – MEAS_CR_RESP)/ REQ_CR_RESP)) **[7]**

Requirement 2

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to its Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the drafting team believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. Additionally, the drafting team understands that Responsible Entities available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying the operators' hands by removing the use of their available contingency reserve from their toolbox for other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in real-time.

Attachment 1

NERC Interconnections 2009-2013

Frequency Events Loss MW Statistics

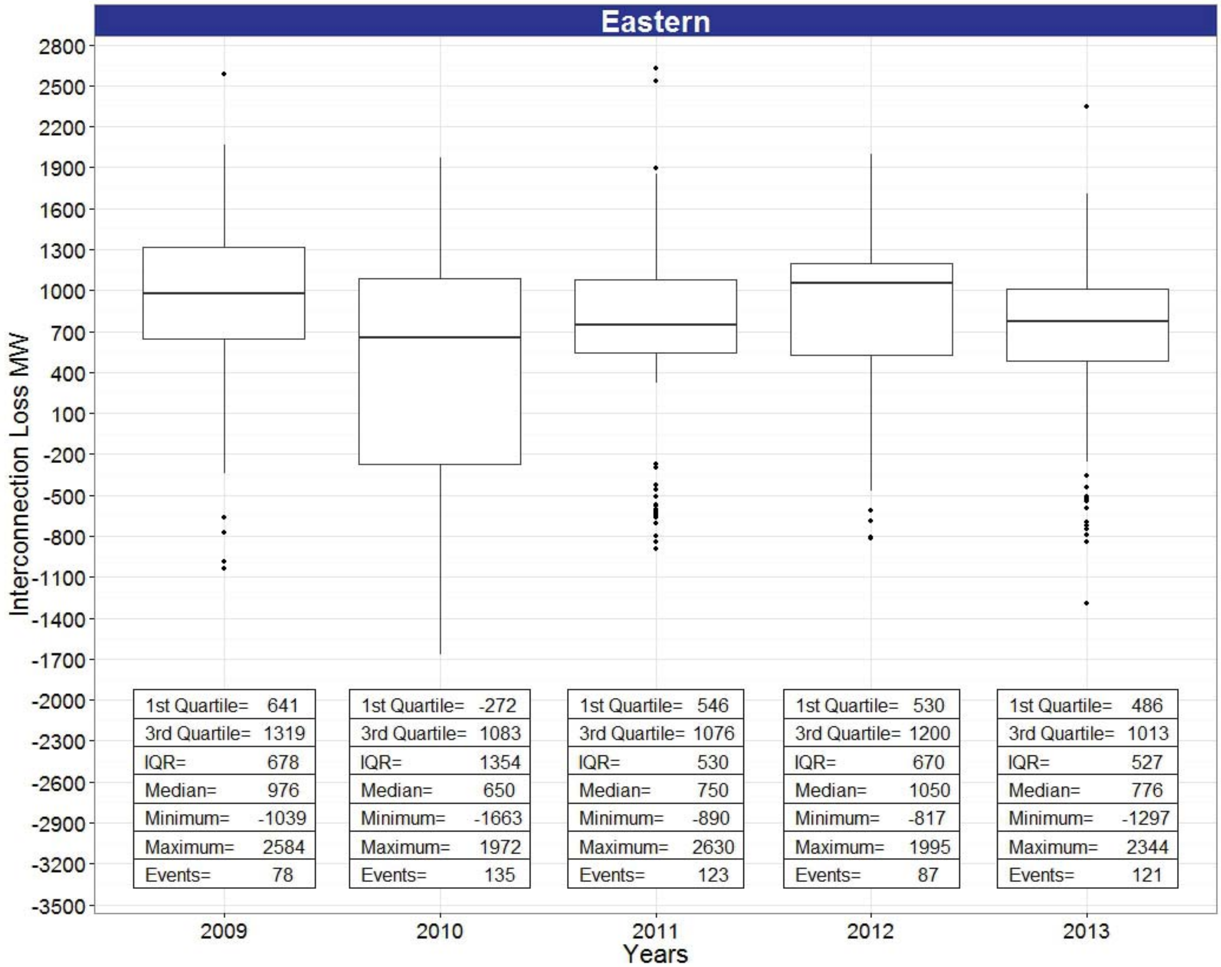
For: NERC BARC Standard Drafting Team

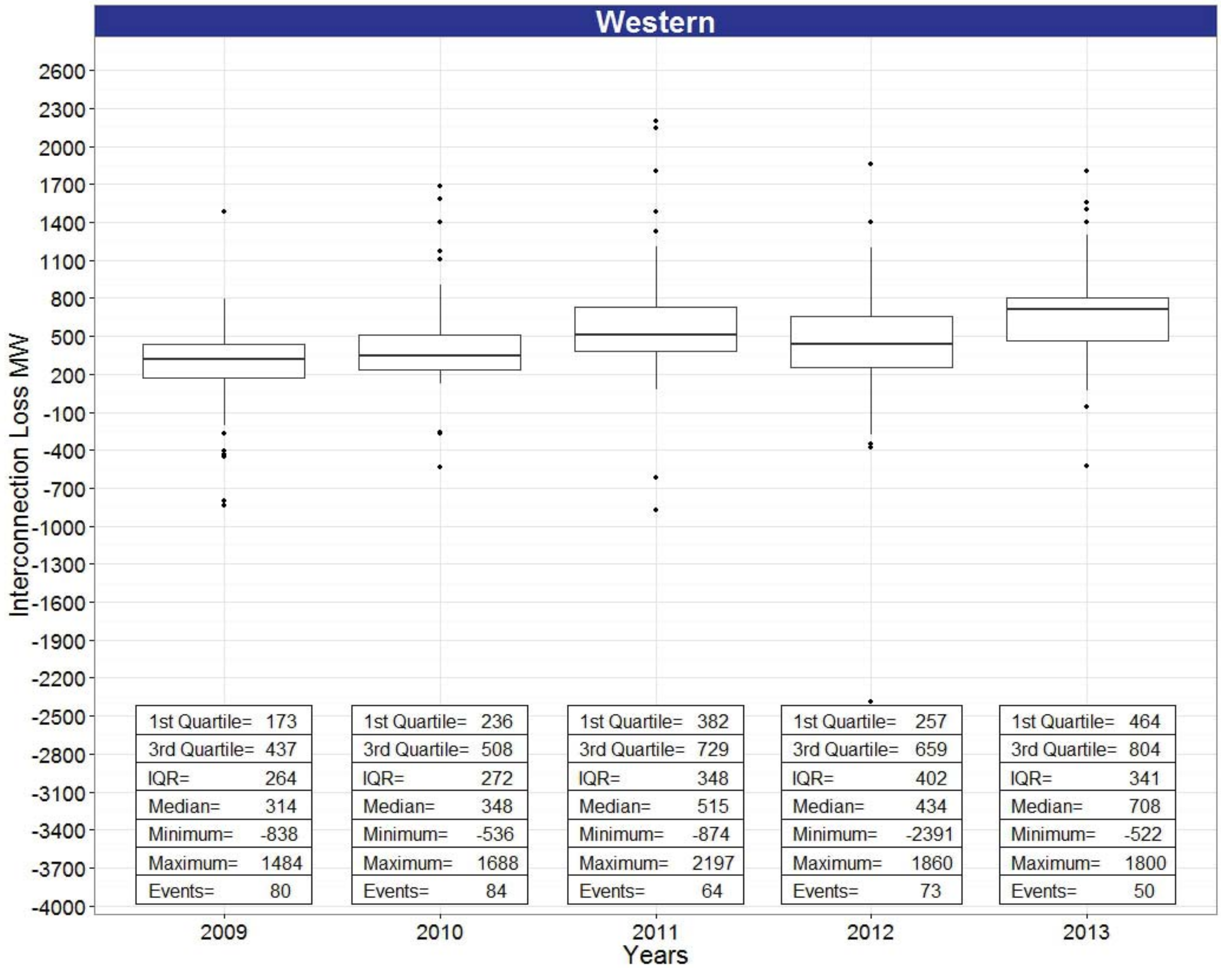
Prepared by: CERTS

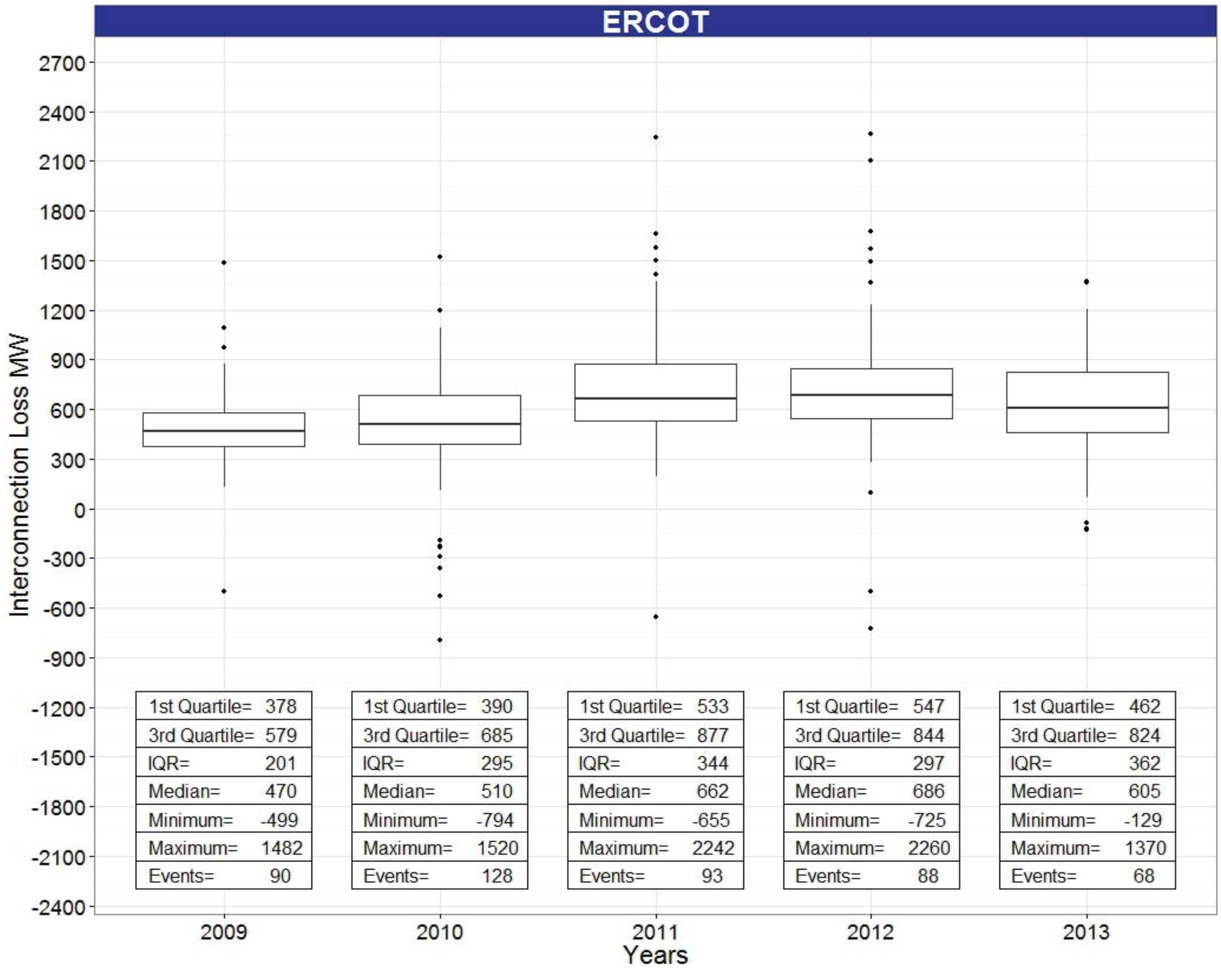
Date: October 15, 2013

CERTS

CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS


Eastern
Interconnection Loss MW
Years
2009
2010
2011
2012
2013
1st Quartile= 641
3rd Quartile= 1319
IQR= 678
Median= 976
Minimum= -1039
Maximum= 2584
Events= 78
1st Quartile= -272
3rd Quartile= 1083
IQR= 1354
Median= 650
Minimum= -1663
Maximum= 1972
Events= 135
1st Quartile= 546
3rd Quartile= 1076
IQR= 530
Median= 750
Minimum= -890
Maximum= 2630
Events= 123
1st Quartile= 530
3rd Quartile= 1200
IQR= 670
Median= 1050
Minimum= -817
Maximum= 1995
Events= 87
1st Quartile= 486
3rd Quartile= 1013
IQR= 527
Median= 776
Minimum= -1297
Maximum= 2344
Events= 121


Western
Interconnection Loss MW
2600
2300
2000
1700
1400
1100
800
500
200
-100
-400
-700
-1000
-1300
-1600
-1900
-2200
-2500
-2800
-3100
-3400
-3700
-4000
1st Quartile= 173
3rd Quartile= 437
IQR= 264
Median= 314
Minimum= -838
Maximum= 1484
Events= 80
1st Quartile= 236
3rd Quartile= 508
IQR= 272
Median= 348
Minimum= -536
Maximum= 1688
Events= 84
1st Quartile= 382
3rd Quartile= 729
IQR= 348
Median= 515
Minimum= -874
Maximum= 2197
Events= 64
1st Quartile= 257
3rd Quartile= 659
IQR= 402
Median= 434
Minimum= -2391
Maximum= 1860
Events= 73
1st Quartile= 464
3rd Quartile= 804
IQR= 341
Median= 708
Minimum= -522
Maximum= 1800
Events= 50
2009
2010
2011
2012
2013
Years


ERCOT
Interconnection Loss MW
2700
2400
2100
1800
1500
1200
900
600
300
0
-300
-600
-900
-1200
-1500
-1800
-2100
-2400
1st Quartile= 378
3rd Quartile= 579
IQR= 201
Median= 470
Minimum= -499
Maximum= 1482
Events= 90
1st Quartile= 390
3rd Quartile= 685
IQR= 295
Median= 510
Minimum= -794
Maximum= 1520
Events= 128
1st Quartile= 533
3rd Quartile= 877
IQR= 344
Median= 662
Minimum= -655
Maximum= 2242
Events= 93
1st Quartile= 547
3rd Quartile= 844
IQR= 297
Median= 686
Minimum= -725
Maximum= 2260
Events= 88
1st Quartile= 462
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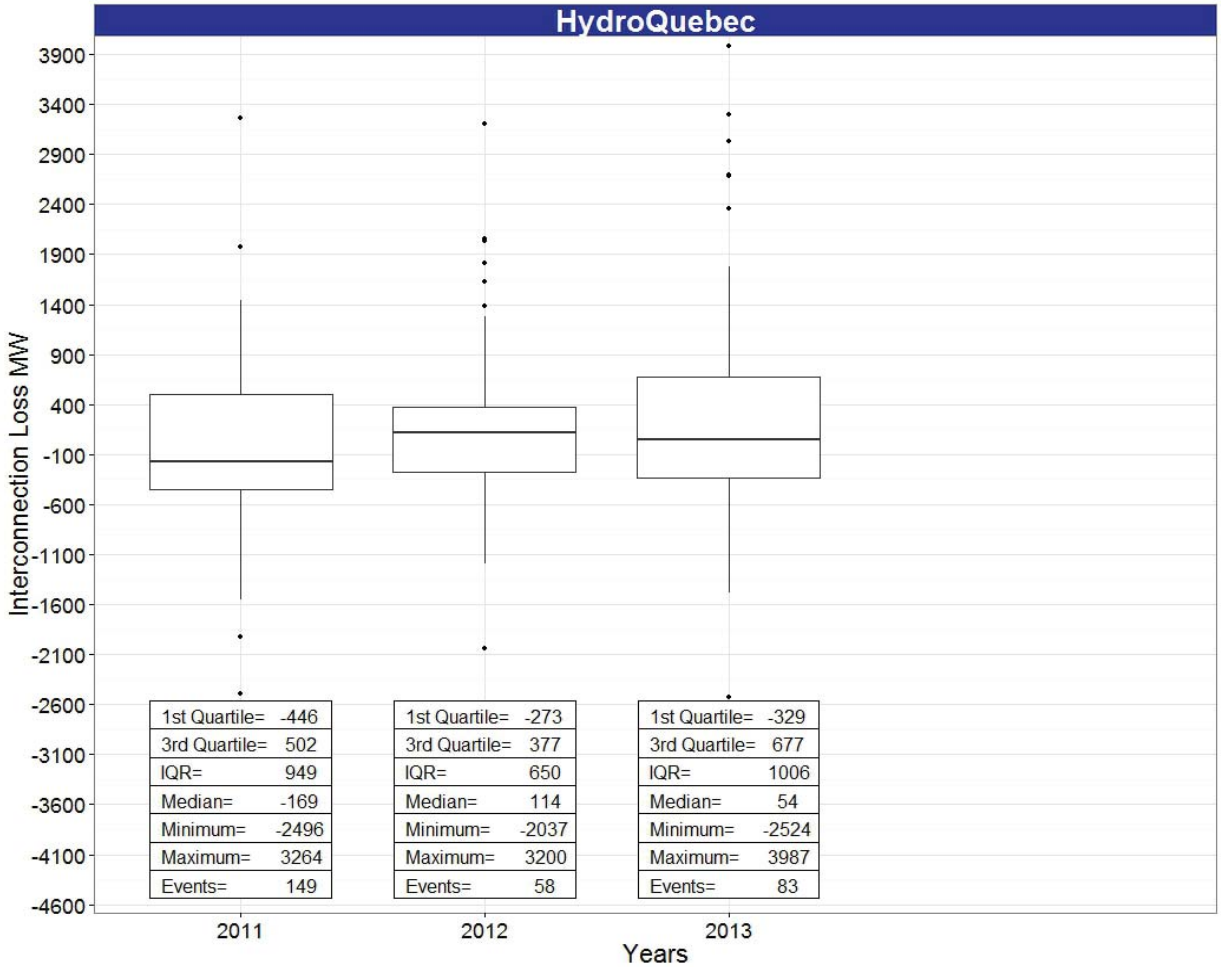
2010
2011
2012
2013
Years



No Data Available for 2009 and 2010

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document

RELIABILITY | ACCOUNTABILITY

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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's most severe single contingency.

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This generating capacity is necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Contingency Event. Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question on who is the applicable entity and assures the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 solely a performance standard. The primary objective of BAL-002-2 is to assure the applicable

entity balances resources and demand and returns its Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. Rather, the combination of the recently passed BAL-001-2 standard, in which R2 requires operation within an ACE bandwidth based on interconnection frequency, TOP-007 and EOP-002, are much better at addressing issues when large events occur. The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL will allow the BA time to quickly evaluate the best course of action and then react in a reasonable manner. The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances that could cause transmission overloads if certain units (typically N-1-1 or greater) where lost and reserves responded. In addition, under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented. Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for and not any loss of resource that would exceed MSSC. Therefore, the definitions and requirements under BAL-002-2 exclude events greater than the MSSC. This will help ensure reliable operation, clarity of requirements and supports reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary requirements assures FERC's requirement is met.

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The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

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Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing contingency reserve definitions primarily focused on generation and not D~~d~~emand S~~s~~ide M~~m~~anagement (DSM). In order to meet FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows ~~Ddemand-s Side Mmanagement (DSM)~~DSM- to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with ~~Ddemand Sside Mmanagement~~DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complimented each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event,~~-~~ a~~A~~nd without a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

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The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

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Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

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The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least:

- Zero~~,~~ (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):~~,~~
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  , O~~o~~r
- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative):~~,~~
  - less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and
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1.1 All Reportable Balancing Contingency Events will be documented using~~The required reporting form is~~ CR Form 1.

1.2. ~~This r~~Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.

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Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entitie~~y'(~~s~~)~~ to have a clear way to demonstrate compliance and support the Interconnection to the full extent of MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a Requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of contingency reserve.

Additionally, R 1 is designed to assure the applicable entity must use reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the drafting team elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of the FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the required contingency reserve response and measured contingency reserve response are computed and compared as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.
- The measured contingency reserve response is equal to one of the following:
    - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.

- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the required contingency reserve response is greater than zero,
    - And the measured contingency reserve response is greater than or equal to the required contingency reserve response, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
    - And the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
    - And the measured contingency reserve response is less than the required contingency reserve response but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((required contingency reserve response – measured contingency reserve response) / required contingency reserve response)).

The above computations can be expressed mathematically in the following 7 sequential steps, labeled as [1-7], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)

SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[2]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[3]**

If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 **[4]**

If REQ_CR_RESP is greater than 0, and,

MEAS_CR_RESP is greater than or equal to REQ_CR_RESP, then

COMPLIANCE = 100 **[5]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[6]**

If REQ_CR_RESP is greater than 0, and, MEAS_CR_RESP is greater than 0, and,

MEAS_CR_RESP is less than REQ_CR_RESP, then

COMPLIANCE = 100 * (1 – ((REQ_CR_RESP – MEAS_CR_RESP)/ REQ_CR_RESP)) **[7]**

Requirement 2

R2. Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity~~ and for an additional five hours during a given calendar quarter~~, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to its Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the drafting team believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. Additionally, the drafting team understands that Responsible Entities available Contingency Reserve may vary slightly from MSSC ~~during~~ at any time~~ of the year~~. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying the operators' hands by removing the use of their available contingency reserve from their toolbox for other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in real-time.~~Thus, to allow for the five hours of exemption by calendar quarter, the drafting modified the requirement to reflect such an exemption. By including the exemption provides the necessary continuity between the requirement and the VSL.~~

Attachment 1

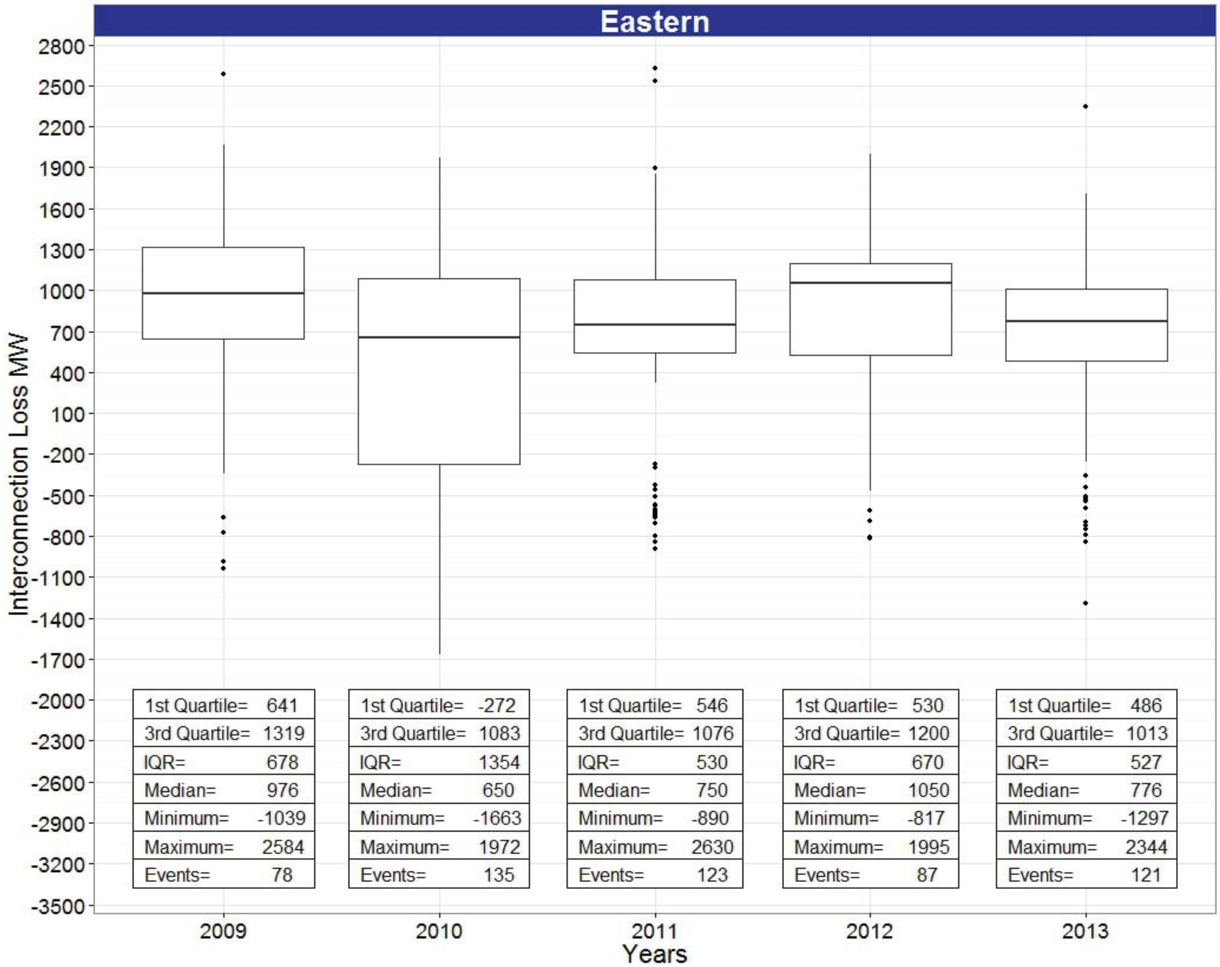
NERC Interconnections 2009-2013

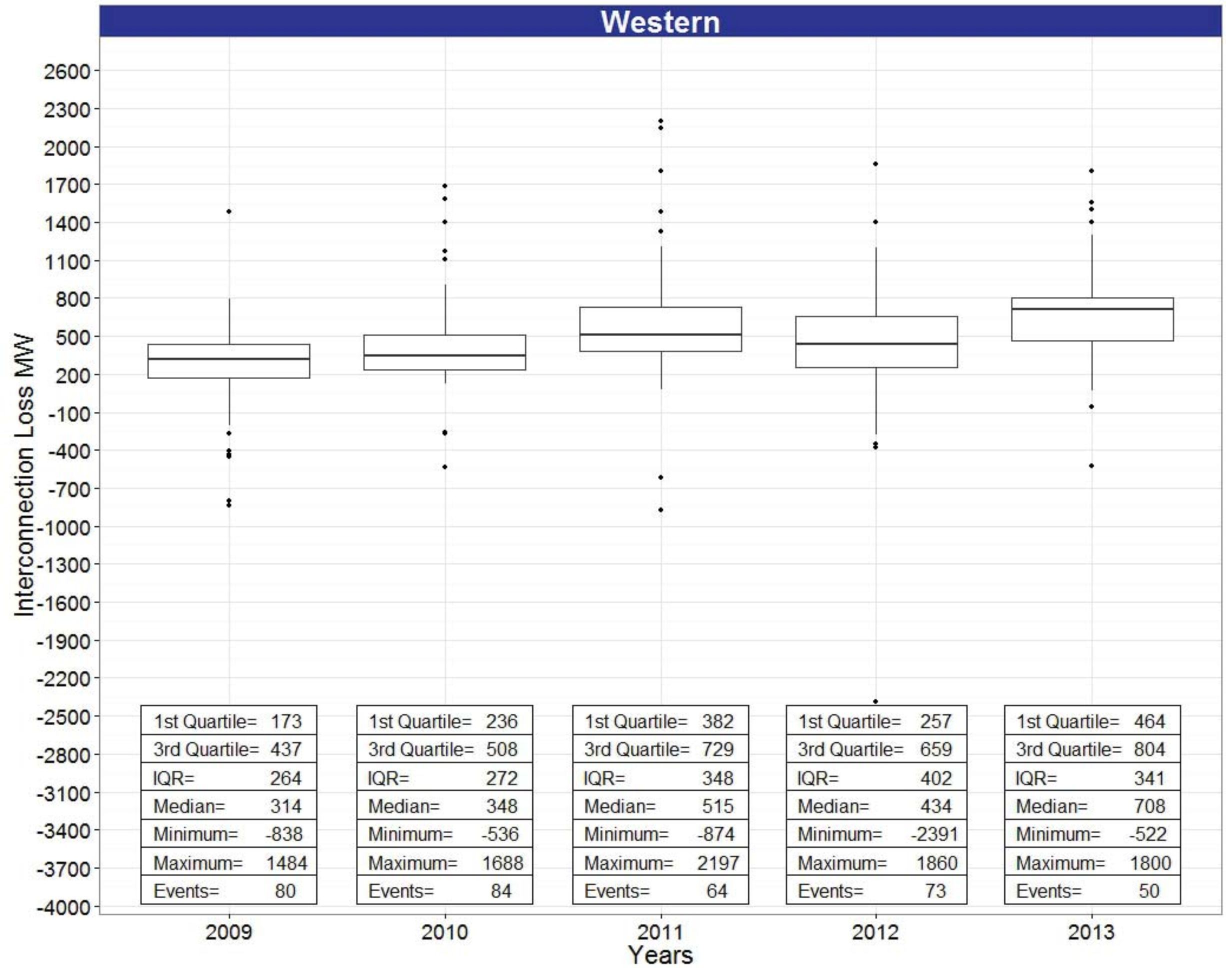
Frequency Events Loss MW Statistics

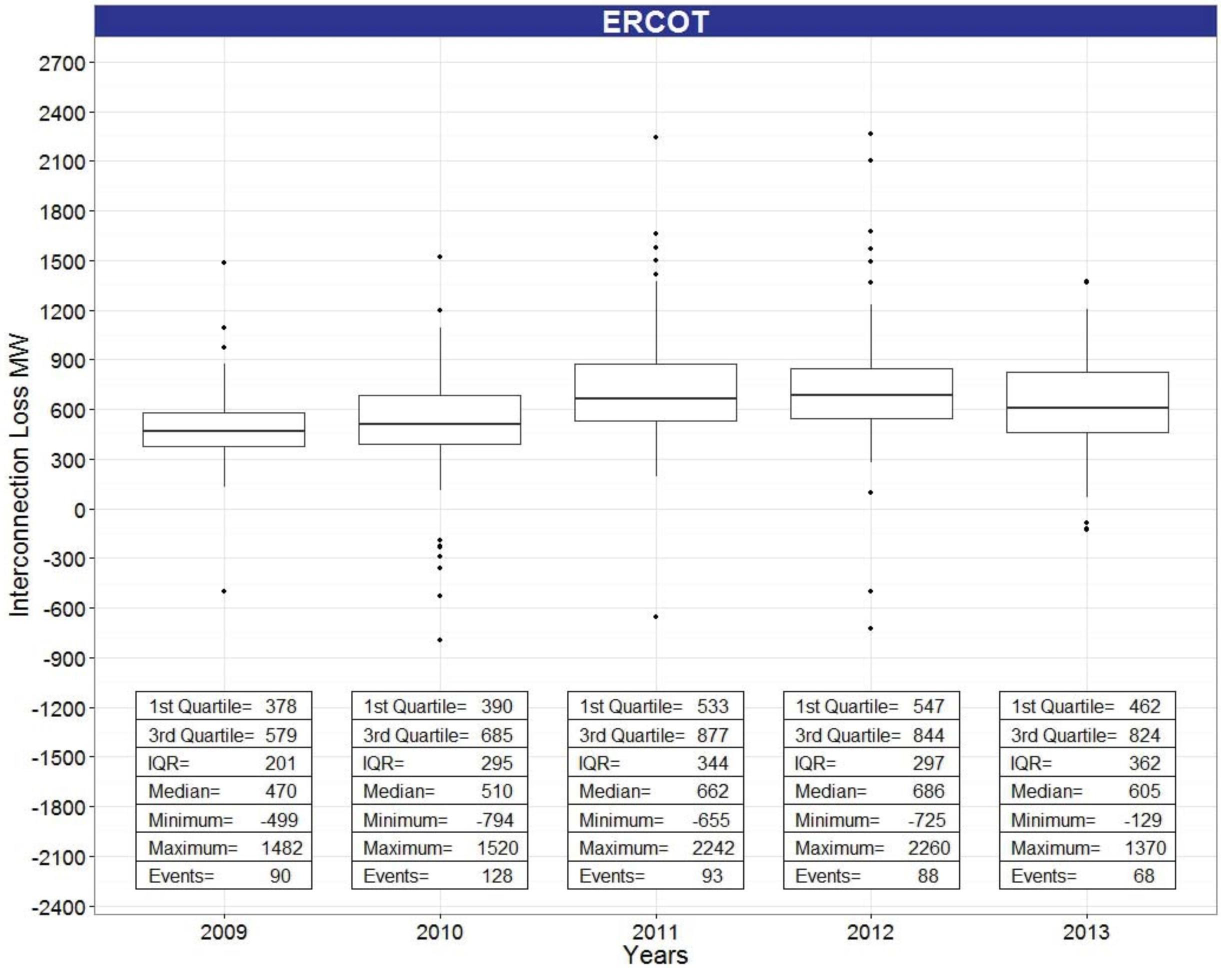
For: NERC BARC Standard Drafting Team

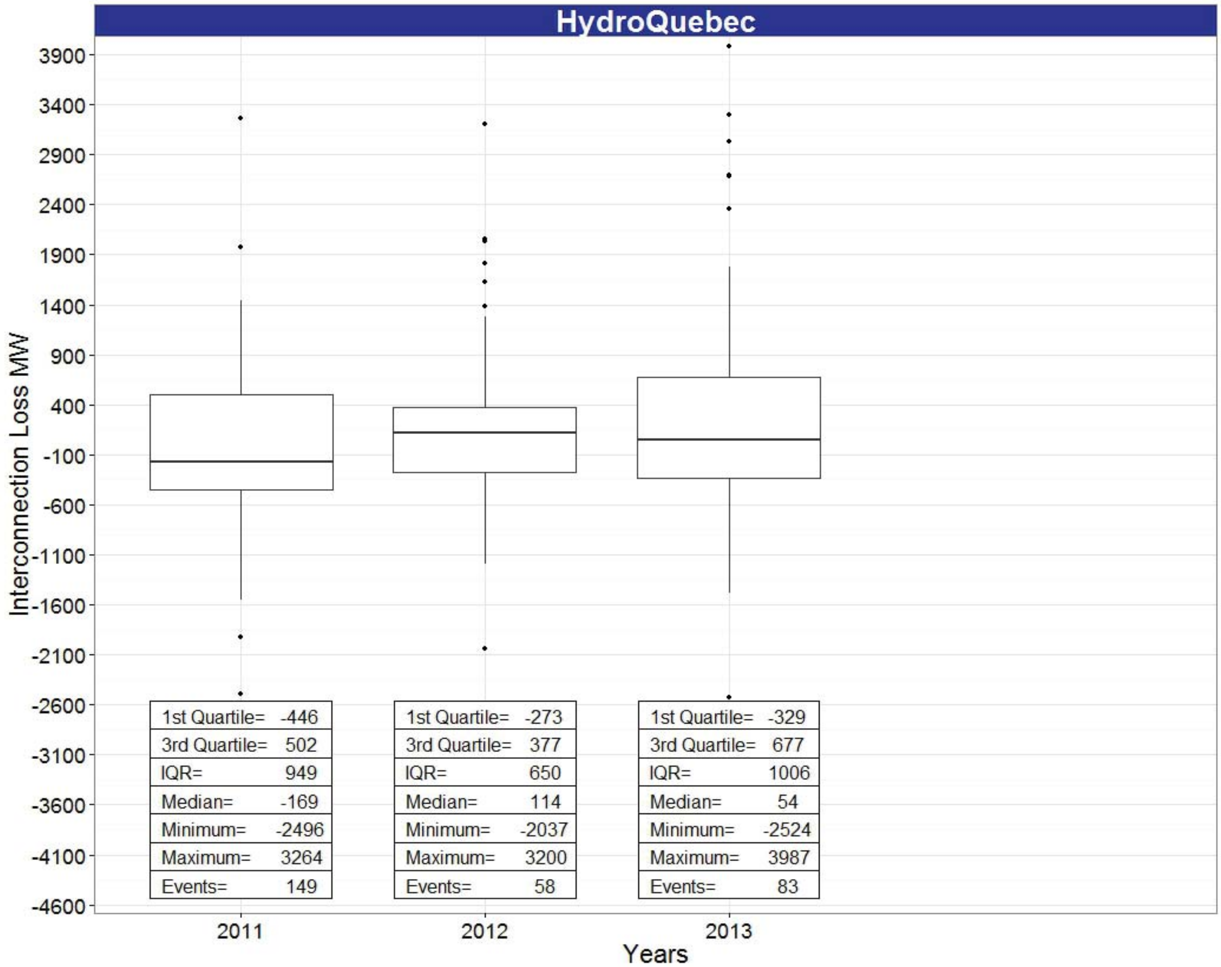
Prepared by: CERTS

Date: October 15, 2013


Eastern
Interconnection Loss MW
2800
2500
2200
1900
1600
1300
1000
700
400
100
-200
-500
-800
-1100
-1400
-1700
-2000
-2300
-2600
-2900
-3200
-3500
1st Quartile= 641
3rd Quartile= 1319
IQR= 678
Median= 976
Minimum= -1039
Maximum= 2584
Events= 78
1st Quartile= -272
3rd Quartile= 1083
IQR= 1354
Median= 650
Minimum= -1663
Maximum= 1972
Events= 135
1st Quartile= 546
3rd Quartile= 1076
IQR= 530
Median= 750
Minimum= -890
Maximum= 2630
Events= 123
1st Quartile= 530
3rd Quartile= 1200
IQR= 670
Median= 1050
Minimum= -817
Maximum= 1995
Events= 87
1st Quartile= 486
3rd Quartile= 1013
IQR= 527
Median= 776
Minimum= -1297
Maximum= 2344
Events= 121
2009
2010
2011
2012
2013
Years


Western
Interconnection Loss MW
2600
2300
2000
1700
1400
1100
800
500
200
-100
-400
-700
-1000
-1300
-1600
-1900
-2200
-2500
-2800
-3100
-3400
-3700
-4000
1st Quartile= 173
3rd Quartile= 437
IQR= 264
Median= 314
Minimum= -838
Maximum= 1484
Events= 80
1st Quartile= 236
3rd Quartile= 508
IQR= 272
Median= 348
Minimum= -536
Maximum= 1688
Events= 84
1st Quartile= 382
3rd Quartile= 729
IQR= 348
Median= 515
Minimum= -874
Maximum= 2197
Events= 64
1st Quartile= 257
3rd Quartile= 659
IQR= 402
Median= 434
Minimum= -2391
Maximum= 1860
Events= 73
1st Quartile= 464
3rd Quartile= 804
IQR= 341
Median= 708
Minimum= -522
Maximum= 1800
Events= 50
2009
2010
2011
2012
2013
Years


ERCOT
Interconnection Loss MW
2700
2400
2100
1800
1500
1200
900
600
300
0
-300
-600
-900
-1200
-1500
-1800
-2100
-2400
1st Quartile= 378
3rd Quartile= 579
IQR= 201
Median= 470
Minimum= -499
Maximum= 1482
Events= 90
1st Quartile= 390
3rd Quartile= 685
IQR= 295
Median= 510
Minimum= -794
Maximum= 1520
Events= 128
1st Quartile= 533
3rd Quartile= 877
IQR= 344
Median= 662
Minimum= -655
Maximum= 2242
Events= 93
1st Quartile= 547
3rd Quartile= 844
IQR= 297
Median= 686
Minimum= -725
Maximum= 2260
Events= 88
1st Quartile= 462
3rd Quartile= 824
IQR= 362
Median= 605
Minimum= -129
Maximum= 1370
Events= 68
2009
2010
2011
2012
2013
Years



No Data Available for 2009 and 2010

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	Applicability 4.1. Balancing Authority 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. 4.2. Reserve Sharing Group 1.4. Additional Compliance Information The Responsible Entity may use Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2

Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		Reserve for any Balancing Contingency Event and as required for any other applicable standards.
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members.	This Requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for any reliability outcome and if violated would not cause separation, instability or cascading outages.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	This Requirement has been moved into BAL-002-2 Requirements R1 and Requirement R2	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC,

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1. 1.2. Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. BAL-001-2 Requirement R2 **2.** Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, average over the Clock Hour, at least equal to its Most Severe Single

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Contingency.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.		Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1. 1.2. This requirement (in its entirety) does not apply

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2
		when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. Contingency Event Recovery Period A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods: R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates	This Requirement has been moved into BAL-002-2 Requirement R1 and Reserve Sharing Group Reporting ACE	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.		completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. **Reserve Sharing Group Reporting ACE** At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of the Balancing

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Authorities participating in the Reserve Sharing Group at the time of measurement.
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection. R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period. R6.2. The default Contingency Reserve Restoration Period is 90 minutes.	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		be documented using CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	Comment	Proposed Standard BAL-002-2

Project 2010-14.1 Balancing Authority Reliability-based Controls - Reserves
BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Mapping Document

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules. R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	Applicability 4.1. Balancing Authority 4.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. 4.2. Reserve Sharing Group 1.4. Additional Compliance Information The Responsible Entity may use Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2

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cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.The Reliability Coordinator and Planning Authority shall each establish a set of inter-regional and intra-regional Transfer Capabilities that is consistent with its current Transfer Capability Methodology.		Reserve for any Balancing Contingency Event and as required for any other applicable standards.
R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: R2.1. The minimum reserve requirement for the group. R2.2. Its allocation among members.	This Requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for any reliability outcome and if violated would not cause separation, instability or cascading outages.

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve. R2.4. The procedure for applying Contingency Reserve in practice. R2.5. The limitations, if any, upon the amount of interruptible load that may be included. R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.		

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.	This Requirement has been moved into BAL-002-2 Requirements R1 and Requirement R2	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o f~~F~~urther reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using~~The required reporting form is~~ CR

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Form 1. 1.2. ~~This r~~Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. BAL-001-2 Requirement R2 **2.** Except during the Responsible Entity's Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or Level 3 for the Responsible Entity, the ~~each~~ Responsible Entity shall maintain an amount of Contingency Reserve, average over the Clock Hour, at least equal to its Most Severe Single Contingency.
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is: R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	BAL-002-0 Requirement R4 and R4.1 to BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value. R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.		o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during~~ prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using ~~The required reporting form is~~ CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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		<u>Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency.</u> Contingency Event Recovery Period A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter. Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable	This Requirement has been moved into BAL-002-2 Requirement R1 and Reserve Sharing Group Reporting ACE	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its <u>Reporting</u> ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero):

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Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods: R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period. or R5.2. The Reserve Sharing Group reviews each member's ACE in		o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC, Or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.		Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using ~~The required reporting form is~~ CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. 1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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		Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency. **Reserve Sharing Group Reporting ACE** At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of ~~all of~~ the Balancing Authorities participating in~~that make up~~ the Reserve Sharing Group at the time of measurement.
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition	BAL-002-2 Requirement R1 **1.** The Responsible Entity experiencing a Reportable

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
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Interconnection. R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period. R6.2. The default Contingency Reserve Restoration Period is 90 minutes.		Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its Reporting ACE to at least: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]* • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero): o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC, Or,

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		• Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative), o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred during ~~prior to that value of Reporting ACE within~~ the Contingency Event Recovery Period, and o Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section~~clause~~ (ii) of this bullet is greater than MSSC. 1.1. All Reportable Balancing Contingency Events will be documented using ~~The required reporting form is~~ CR Form 1. 1.2. This requirement (in its entirety) does not apply when the Responsible Entity experiencing a

BAL-002-0 Mapping to Proposed NERC Reliability Standard BAL-002-2		
Standard BAL-002-0 NERC Board Approved	**Comment**	**Proposed Standard BAL-002-2**
		Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3. <u>1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency.</u> Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-002-2)

Formal Comment Period: October 28, 2013 – December 11, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: December 2-11, 2013

Now Available

A formal comment period for **BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern on Wednesday, December 11, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for the standard is open through **8 p.m. Eastern on Wednesday, December 11, 2013**. Please use the electronic comment form to submit comments.

An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **Monday, December 2, 2013** through **8 p.m. Eastern on Wednesday, December 11, 2013.**

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 (via email), Standards Development Administrator, or at 404-446-2560.

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Individual or group. (32 Responses)
Name (20 Responses)
Organization (20 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (32 Responses)
Question 1 (23 Responses)
Question 1 Comments (25 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Firstly, we would like to thank the SDT for their efforts and consideration of these comments. We continue to disagree with defining new terms that are unique to this standard and then including them in the NERC Glossary when the standard is approved. Many of these terms are used exclusively in this standard only, and as such, should be kept within this standard and not moved to the NERC Glossary. Moving these terms to the NERC Glossary creates an unnecessary maintenance burden, and may create a conflict with similar terms used in other NERC documents. We agree with the Drafting Team's goal to better define when the requirements apply. The approach taken makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. There are different approaches used in the standards to say when a requirement applies and when it doesn't ("exemptions", "exclusions", or "does not apply"). We suggest an alternative approach that would simplify the requirements. We recommend adding a Part under each requirement detailing exclusions. Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] (footnote 1 below) • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the Drafting Team to use simpler wording for the requirements. Footnote 1--The IROL standards still require operators to take whatever action is necessary to prevent cascading with the next contingency, to include shedding load or redispatch. The new BAL-001 standard will require the Balancing Authority to take action within 30 minutes to get frequency back within acceptable bounds. The Energy Emergency Alert process still exists to address any reserve shortfall. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multiple contingencies occur, we want the operator to assess their actions based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the Drafting Team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the Drafting Team decide to not retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2: As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for

carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to “bank” average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don’t withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. What is the driver for this requirement? It is not within the scope of the Drafting Team’s SAR, nor was it directed in Order No. 693. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. One approach is to include a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. For example, consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won’t be able to fully recover them for 90 minutes (same as the current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren’t directly measured? Proposed Solutions: As noted earlier, we recommend including exclusions that will allow simplification of the requirements. The two requirements could then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have: R2. The Responsible Entity’s hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours. In addition regarding R2, the removal of the “five hours exemption” in R2 is not an enhancement since it could encourage some BAs to avoid activating their contingency reserves in some situations to avoid being non-compliant. For example, if there is an important un-forecasted increase of demand, an IROL limit violation or a voltage problem, the activation of contingency reserve could probably most of the time resolve the problem. With the new proposition it would lead to a non-compliance on R2 of BAL-002-2. Because of this the 5 hours exemption should be considered to be kept for reliability reasons. Considering the Quebec Interconnection, there are contingencies that occur where generation and load are lost at the same time. There are contingencies where 1900 MW of generation is lost and 1600 MW of DC converters at the same time, the net loss for the BA/Interconnection being 300 MW. The net loss causes a small ACE change and is under the Reportable Balancing Contingency Event threshold. In addition, the 1600 MW of DC converter loss would probably be reported by another entity as a DCS due to a loss of an import. For this reason, suggest that the Balancing Contingency Event and the Reportable Balancing Contingency Event definitions be revised to include the concept of net loss for the BA instead of only the generator MW output. As for the Reportable Balancing Contingency Event threshold, the 500 MW threshold for the Quebec Interconnection should be reconsidered. As for now, the actual threshold set at 80% of MSSC which corresponds generally around 800 MW already traps events that are significant for the Interconnection and truly measure events where contingency reserve is being deployed by operator actions. A too low threshold might capture events that are recovered with frequency response and AGC action, which are deployed quickly after the event since Quebec is in a

single BA Interconnection. The proposed threshold in the draft would augment the reporting needs without any improvement in measuring contingency reserve deployment.
Individual
Thomas Foltz
American Electric Power
Yes
AEP questions if this new version is an improvement over the current BAL-002-1. There are many more terms that are cross referenced and it will become a risk that operators will struggle to tie all the pieces together. This proposed standard, while it might be more flexible in some regards, might cause unnecessary confusion. AEP recommends changing the definition for Balancing Contingency Event to the following: "Any single event described below, or any series of such otherwise single events, with each separated from the next by less than one minute and, that causes a significant change to the responsible entity's ACE caused by 1. Sudden loss of supply (generation or import), not including controlled shutdown of a unit. …or … 2. Restoration of a load" Reserve Sharing Group Reporting ACE: the addition of the "at the time of measurement" is now stated twice in the same sentence. We believe one of the references should be removed. R1 1.1, 1.2, and 1.3: The content provides guidance and exception information, but includes no obligatory language. As a result, these sub requirements should instead be moved into either footnotes or bullet points. R2 is very difficult to follow with all of the exceptions. Furthermore, it would be better to start with the expected obligation and have the exceptions to the rule follow in the sentence or maybe in a footnote. We do support some amount of a "grace period" during these events, however, what is the reliability basis for the 5 hour duration?
Individual
Gerald G Fattinger
Consumers Energy
Yes
a) The definition of Balancing Contingency Event is long and cumbersome. Any loss of generation or import no matter how minor is considered a Balancing Contingency Event. The true trigger for an Event should be a change in the ACE of a specified amount of percentage. The cause of the deviation (other than meter or telemetry error) is immaterial and has no real impact on actions taken. b) Having a definition of a Contingency Event and a Reportable Contingency Event is piling on. One definition is all that is required. c) Applicability to a Reliability Standard should not be dependent on an Event. This is either applicable to a BA or RSG or it is not. The fact that the measurement only happens when a Recordable Event occurs is irrelevant to the applicability. d) This standard is difficult to read through and overly complicated. e) Definitions in BAL-002-1 are clear and succinct. They should remain for this standard.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We continue to disagree with defining new terms and move them to the NERC Glossary when the standard is approved. Many of these terms are used exclusively in this standard only, and as such, should be kept within the standard and not be moved to the NERC Glossary. Moving these terms to the NERC Glossary creates unnecessary maintenance burden, and may create a conflict with similar terms used in other NERC documents. A Balancing Contingency Event is vaguely defined as a "Sudden loss of generation..." or "sudden decline in ACE...". The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where we say that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE

definition: Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Although supportive of the drafting team's efforts to improve BAL-002, LES is concerned with the proposed definitions of Most Severe Single Contingency (MSSC) and Reportable Balancing Contingency Event. As drafted, the definition of MSSC does not clearly state whether or not the Reserve Sharing Group (RSG), or the Balancing Authority not in a RSG, can define whether or not the MSSC is operationally defined or defined in advance. Additionally, the definition of Reportable Balancing Contingency Event is confusing as proposed. Recommend the drafting team consider incorporating a formula within the definition to provide additional clarity.
Individual
Kathleen Goodman
ISO New England Inc.
We believe the term “sudden” should be defined as a “step change.” Does “imbalance between generation and load on the Interconnection” imply causing an imbalance beyond the BA or RSG boundary? Could that mean that associated transaction curtailments factor into the overall contingency size? “Begins to decline” in the definition of Contingency Event Recovery Period should be “Begins to decline unexpectedly.” “Averaged over each Clock Hour” should be averaged over three to five clock hours so as to be manageable practically from an operational perspective. Suggest modifying R2, as: “R2. Except during the Responsible Entity’s Contingency Event Recovery Period and the Responsible Entity’s Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over a rolling (3-5) Clock Hour interval at least equal to the average of the Most Severe Single minus the average Area Control Area over the same interval.” Generally speaking, the requirement to maintain an amount of Contingency Reserve at least equal to its Most Severe Single Contingency may, in fact, reduce reliability. As we read it, the only two reasons that these reserves may go below MSCC are: during an EEA 2 or 3; or during the Contingency Reserve Restoration Period. Therefore, in order to maintain compliance, one might not deploy reserves for events such as a missed load forecast, opting instead to “drag” on the Interconnection. This seems counterintuitive to a reliability standard. Requirement 1.2 does not provide clarity as to the applicable EEA 2/3 trigger. Can the Contingency Event itself trigger the EEA? Assuming it cannot, alternate language may be: “1.2. Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3 at the time that the Reportable Balancing Contingency Event occurs.”
Individual
Marie Knox
MISO
Yes
We appreciate the efforts of the drafting team as well as the opportunity to comment. Our primary concern is that this project is taking a step back from performance-based standard and moving

toward a zero-defect commodity obligation. The intent of the original Policy 1 DCS was to prepare for contingencies of any type and restore balance after they occur. It was understood that multiple events and unforeseen situations arose. This is why performance was measured over many events over a quarter. What is now proposed will likely lead to several negative unintended consequences (added cost for no identified need, wider intra-hour frequency variation to as BAs change dispatch to always have a given hourly average, fewer reportable events as each event is singularly sanctionable, and a likely step increase in the calling of EEAs 2 and 3). The reality is most of the Order No. 693 items the team is attempting to address have already been more effectively covered by BAL-001-2 R2 (commonly called BAAL). Simplifying the Verbiage in the Standard While we agree with the drafting team's goal to better define when the requirements apply, the wording makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. The current standards use several different approaches to say when a requirement applies and when it doesn't (search on "exemptions", "exclusions", or "does not apply" to find examples). We suggest the following to make the requirements simpler. First, we recommend adding an "Exclusions" section under "Applicability". Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the drafting team to use simpler wording for the requirements. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multi-contingent events occur, we want thoughtful and measured action on the part of the operator. In most cases the first priority is to assess their actions based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the drafting team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the drafting team reject the comment to retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2 As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to "bank" average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. We could offer one approach to including a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. A scenario would help explain this suggestion. Consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won't be able to fully recover them for 90 minutes (same as the

current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Proposed Solutions for the Standard As noted earlier, we recommend including an "Exclusions" subsection under "Applicability" that will allow simplification of the requirements. The two requirements can then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have R2. The Responsible Entity's hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours. Other Recommendations to Support Reliability We again suggest an informed approach to first provide simple definitions of the different types of reserves (in particular for this standard, contingency reserves and replacement reserves). Once these terms are defined and commented on by the Industry, NERC should add these types of reserves to "Attachment 1-TOP-005 Electric System Reliability Data" with the expectation that Reliability Coordinators collect this information in real time for use in the EEA process. We believe there would be significant reliability value in giving RCs visibility of the current state of Contingency Reserves (something callable in 10 minutes, fully deployed in 15 minutes and sustainable for at least 90 minutes) and Replacement Reserves (something callable in 90 minutes and sustainable for say 4 hours). This would directly contribute to reliability by providing objective information to BAs and RCs in managing Energy Emergency Alerts.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co.
Agree
MISO
Group
Duke Energy
Michael Lowman
Yes
(1) Duke Energy believes that the existing definition of a Balancing Contingency Event is redundant and imprecise. We recommend that the definition be revised as follows: Balancing Contingency Event: Any single event described in Subsections (A) or (B) below, or any series of such otherwise single events, with each separated from the next by less than one minute. A. Sudden loss of generation or import due to Unit tripping or the sudden unplanned outage of transmission Facility that causes an unexpected change to the responsible entity's ACE; B. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. Duke Energy has previously commented that Item B of the existing Balancing Contingency Event definition should be removed because it is already covered under Item A. The modification of Item (A) to include "Sudden loss of generation or import…" makes it clear and explicit that Item (A) includes the loss of an import due to either unit trip or the sudden unplanned outage of a transmission facility. In addition, there is no need to cover the loss of Interconnection Facilities in the existing section (A)(a)(ii) because Interconnection Facilities are included in transmission Facilities and would also necessarily result in a unit trip, and both of these circumstances are covered elsewhere in the definition. The existing definition also refers to "unplanned outage of transmission Facility" in section (A)(a)(ii) versus the reference to "forced outage of transmission equipment" in section (B). Duke believes that describing transmission outages using different terms within the same definition will result in confusion and differing interpretations of the meaning of the definition. The proposed

elimination of section (B) resolves this issue as well. (2) Regarding Requirement 2, Duke Energy still maintains that this Standard should remain a results-based Standard and not burden responsible entities with the tracking of reserves maintained. The existence of a requirement such as R2 will result in inefficient utilization of resources, increased costs, inaccurate representation of resource capability, and other negative consequences with no benefit to reliability. (3) Duke Energy suggests combining and rewording sub-requirement 1.2 and 1.3 as follows: "R1.2 Requirement R1 (in its entirety) does not apply to the Responsible Entity if any of the following occurs: 1.2.1 The Responsible Entity experiencing a Reportable Balancing Contingency Event is also experiencing an Energy Emergency Alert Level 2 or Level 3. 1.2.2 The Responsible Entity experiencing a Balancing Contingency Event has an additional event causing the sum of the aggregated events to exceed its MSSC within 15 minutes of the original BCE. 1.2.3 A subsequent BCE that occurs beyond the 15 minute period but is within 105 minutes of the first Balancing Contingency Event provided that the sum of the BCEs exceeded the Responsible Entity's Most Severe Single Contingency." We feel that this wording describes more clearly those instances where a Responsible Entity is not required to report the event as described in Requirement 1.
Group
IRC Standards Review Committee
Terry Bilke
Yes
Background and General Comments We appreciate the efforts of the drafting team as well as the opportunity to comment. We agree with the drafting team's goal to better define when the requirements apply. The approach taken makes it difficult to follow the true meaning of the requirements. We get differing opinions among our peers on what the standard is saying. There are different approaches used in the standards to say when a requirement applies and when it doesn't ("exemptions", "exclusions", or "does not apply"). We suggest an alternative approach to make the requirements simpler. We recommend adding an "Exclusions" section under "Applicability". Exclusions: • R1 and R2 do not apply during EEA 2 or EEA 3. • R1 does not apply for multiple non-simultaneous events [Rationale: These events are adequately addressed by IROL, BAAL and EEA requirements] • R1 does not apply for single or simultaneous events where the capacity loss is > MSSC. This will allow the drafting team to use simpler wording for the requirements. Comments on R1 Events > MSSC. As noted earlier, events where the capacity (not solely MW) loss > MSSC should not be evaluated under this standard. Even if the MW loss was within the reporting threshold, the BA would have lost the reserves it needed to assist the recovery. We agree that events > MSSC can be reported on a different sheet on the reporting form, but there should not be an associated measure. The report should capture the time, unit, power, and capacity loss. Multiple lines on the report would be needed for each event series. When multi-contingent events occur, we want thoughtful action on the part of the operator. In most cases they should assess their actions first based on impact on the transmission system rather than achieving a zero ACE. As noted earlier, there are protective backstops in place (IROL, BAAL, EEA). Change from Quarterly Metric. DCS performance has always been calculated and reported on a quarterly basis. This is similar to CPS1 and CPS2 whose performance is based on annual and monthly calculations. While we understand that this change was a directive in Order No. 693, the drafting team has the option to point out the rationale why the directive will have unintended consequences. We believe this single event metric will lead to changes in how Reserve Sharing Groups select events, only reporting those very large events rather than allowing members to call for reserves for smaller contingencies. This is a step backward from a reliability perspective. Should the drafting team reject the comment to retain the quarterly metric, we strongly recommend staying with a quarterly report form with each event listed separately to reduce the administrative overhead. Comments on R2 As proposed we believe this requirement will have significant negative unintended consequences. Reserves are an inventory intended to be used when there is a reliability need. The original Policy 1 listed multiple reasons for carrying operating reserves (errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity). The first unintended consequence is that BAs are discouraged from deploying their contingency reserves except for DCS-reportable events. There will be a reluctance to deploy reserves if it will take the balance to less than MSSC. We may also experience repeated frequency swells at the start and end of each hour as BAs try to "bank"

average reserves or make up for earlier deficiencies early in the hour. The second unintended consequence for those BAs that don't withhold contingency reserves for non-DCS events is that they will be obliged to increase the amount of contingency reserves they carry so they always have more contingency reserves than their MSSC. This will increase costs to our customers without a demonstrated need. We struggle to understand the driver for this requirement. It is not within the scope of the drafting team's SAR, nor was it directed in Order No. 693. DCS performance in North America has been stellar compared to what was considered adequate performance under Policy 1. We could offer one approach to including a commodity measure that fits within the context of the original DCS and would not discourage the operator from deploying reserves for non-reportable events. A scenario would help explain this suggestion. Consider a medium size BA that has heavier than expected loads due to rain/darkness and associated wet coal conditions at one or more of its plants: • The operator starts falling behind on the load pickup, but deploys most of its on-line reserves to keep up with load. • Because of the wet coal, there are some limitations on the units that further reduce its reserves. • The operator finds out 10 minutes after the hour that they were < MSSC on reserves for the previous hour. • The operator initiates action to replenish reserves, but since s/he is already well into the hour, s/he won't be able to fully recover them for 90 minutes (same as the current standard expects). This means the operator did the right thing, but had 3 hours where reserves were < MSSC. As long as the operator had a plan and could withstand the next contingency, there is no negative impact on reliability. Finally, as we noted in the informal posting of this standard, the team has not provided a simple, clear definition on how contingency reserves are measured as prosed under R2. The definition should be something that can be implemented in an EMS. Does it include all generation headroom available in 10 minutes? In 15 minutes? Do regulating resources with headroom count as contingency reserves? Are load resources available in 15 minutes or 10 minutes counted? What about demand response resources that aren't directly measured? Proposed Solutions As noted earlier, we recommend including an "Exclusions" subsection under "Applicability" that will allow simplification of the requirements. The two requirements can then be simplified as follows: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, return its ACE to at least: • Zero, if pre-contingency ACE was positive or equal to zero. • Pre-contingency ACE value, if pre-contingency ACE was negative. We offer two suggestions for R2: R2. The Responsible Entity experiencing a Reportable Event shall replenish its Contingency Reserves within 105 minutes of the onset of the Reportable Event. Alternatively, it would be consistent with the current standard to have R2. The Responsible Entity's hourly average Contingency Reserves shall not be < its MSSC for more than three consecutive clock hours.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word "shall" instead of "will" to make mandatory the use of the noted CR Form 1. Also, the SDT responses to the last comment period indicated that the CR Form 1 would be included as an attachment to the standard, but after review the form has yet to be attached. ReliabilityFirst recommends attaching it to the standards along with the following change for consideration: "All Reportable Balancing Contingency Events [shall] be documented using Attachment 1 - CR Form 1." 2. Requirement R1, Part 1.3 - For consistency with the second sentence of Requirement R1, Part 1.3, ReliabilityFirst recommends using the word "shall" in the first sentence. ReliabilityFirst recommends the following for consideration: "Requirement R1 (in its entirety) [shall] not apply…" 3. Requirement R1, Part 1.3 - ReliabilityFirst requests the rationale behind using the 105 minute timeframe referenced in the second sentence of Requirement R1, Part 1.3. ReliabilityFirst is trying to understand if there is any technical merit behind this timeframe or if it is solely based on SDT experience. 4. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst

recommends completely removing the second paragraph within Measure M2 from the standard. 5. VSL Requirement R1 - There is no VSL associated with an entity failing to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1. ReliabilityFirst recommends the following for an additional Moderate VSL: "The Responsible Entity failed to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1"
Group
Seattle City Light
Paul Haase
Yes
R2 cannot be implemented or audited as written. There are two flaws. The first flaw is that R2 requires entities to carry Contingency Reserves equal to its MSSC. The problem is that Contingency Reserves, as specified in the draft, are "averaged over each clock hour" whereas MSSC is defined as the MW output of the largest source AT THE TIME OF AN EVENT; i.e. the requirement demands the logical impossibility of measuring an hourly average against an instantaneous value. Absent an event, the comparison cannot be made. The second flaw is that by defining Contingency Reserves as an hourly average, entities are left chasing a target that is not defined until an hour is over. It is possible to employ a conservative reserve profile for the first half of an hour and then ramp up as necessary to meet the target, as it become better known. Employed broadly, this approach could leave the BES short of reserves during the first half of each hour, and does not improve reliability. Seattle recommends that the draft be changed to require an instantaneous value of Contingency Reserves to address both of these flaws. Seattle recognizes the effort of the Standard Drafting team to afford flexibility in meeting Contingency Reserve requirements, but finds the approach as written to be unworkable. Although we ballot in support of the present draft, to indicate that it represents an improvement over existing Standard, Seattle will vote NO for future drafts that do not address the flaws in R2 as presently written.
Group
Southern Company: Southern CompanyServices, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Yes
Southern disagrees with removing the additional 5 hours in a given calendar quarter and the changes made to the VSLs for R2. The industry and NERC are trying to move away from the "zero defect" concept, and the changes to this draft of the standard reintroduce the "zero defect" concerns. As currently drafted, an entity could have one clock hour where the average Contingency Reserve is 99% of the MSSC and be found non-compliant under R2. Southern recommends incorporating a reasonable tolerance period into R2 so that an entity is not in violation in this example.
Individual
Howard F. Illian
Energy Mark, Inc.
No
I have no issues with this draft and support its implementation.
Individual
Oliver Burke
Entergy Services, Inc.
Yes

Entergy does not support the use of an hourly metric as it will force unnecessary, expensive, and counterproductive activities to meet a compliance requirement. NERC SDT should consider longer time increment.
Individual
Silvia Parada Mitchell
NextEra Energy
Yes
Section - Definitions of Terms Used in Standard Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection. NextEra comments: There are other mechanisms to handle sudden loss of import and sudden unplanned outage, this should not be in this standard. The IROL standards require operators to take action to prevent reliability issues including redispatch and shed load. Having FRSG groups activate Contingency Reserves could have unintended consequences. Examples: In the event that multiple BAs are being affected by the reduction of the import; if all BAs call for reserves the overall recovery will be delayed since the BAs will be importing and exporting power. If TLR is used to curtail import due to reliability issue and the transaction affected was between two or more members of the same FRSG group, the call for reserves will negate the loading relief of the TLR. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. NextEra comments: This should not be part of BAL-002. Restoration of load should be done in a controlled manner and if a BA does not have sufficient generation to restore firm load, then the EEA process should be followed.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
(1) Reportable Balancing Contingency Event, D2 - to improve clarity, we suggest removing "equal to". We realize that this will result in some MW difference. For example: Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity. So, if the MSSC is 1000MW and no wording is changed, the reportable range would be 800MW -1000MW. If "equal to" is removed, then the reportable range is 801MW – 999MW. (2) R1, 1.2 – this statement may not be necessary given the language in 4 about the applicability of the standard. It seems redundant. (3) R1, 1.3 – the word 'is' appears to be missing from before the word 'experiencing'. Also, to be consistent, the second sentence should say 'R1 (in its entirety) also shall…'. (4) R1, 1.3 – "an Balancing Contingency …" should be "a Balancing Contingency" (5) R2 – as in R1, 1.2, the carve out for an Energy Emergency Alert does not seem necessary given section 4. (6) M2 – Clock Hour is not consistently capitalized. There is no explanation of what EEA 2 or EEA 3 is. (7) Compliance, 1.4 – again, the carve out for Energy Emergency Alert does not seem necessary given section 4.
Individual
Robert Blohm
Keen Resources Ltd.
Yes
SUGGESTED IMPROVEMENTS TO THE STANDARD Re R1: Remove the comma before the parenthesis, in 2 places Re R1.3 To meet FERC's objection that as written R3 impairs reliability by stopping recoveries in process from completing, append to the very end of subsection 1.3 of

Requirement R.1: “This exemption does not retroactively apply to any recovery in process. The ACE compliance threshold of any recovery in process should still be adjusted per Requirement R.1 by all events subsequent to the last event in recovery that fall within the Contingency Event Recovery Period of the recovery in process.” Re R2 R2's contingency-reserve requirement should be replaced by this frequency-adjusted simple time-relative contingency-reserve requirement metric: Monthly average of (Hourly average Reserve / Hourly average of (GenerationDeployed + Load + BiasShareOfHourlyAverageDeltaFinMW)) >= >= MSSC / Monthly average of Hourly average of (GenerationDeployed + Load + BiasShareOfHourlyAverageDeltaFinMW). The frequency adjustment gives equal weight to the RE’s system reliability obligation as to its load obligation and its generation deployment. Since bias is a negative number, the frequency adjustment relieves the reserve requirement when the RE is contributing to over-frequency and increases the reserve requirement when the RE is deemed to be contributing to under-frequency. Re R3: "experiencing an" should be "experiences a" SUGGESTED IMPROVEMENTS TO THE BACKGROUND DOCUMENT Re "Requirement 1" section: The second line should not be indented. The outer bullets should be dots, not circles, in conformity with the Standard's style. There should be no comma before "Or". Re "Compliance Calculation" section: Insert as the preamble of the section the paragraph "It is very important to note that compliance is calculated in a way equivalent to the wording of Requirement R1, but in a way opposite to the wording of R1. In particular, R1 lowers the Target ACE to exempt subsequent events from the recovery requirement because the Reportable ACE observed by operators cannot be adjusted for subsequent events. On the other hand, the compliance calculation per CR Form 1 does not adjust the Target ACE for subsequent events and instead adjusts the Reportable ACE by removing the subsequent events from the Reportable ACE. The compliance result is the same either way, but this difference needs to be noted to properly understand the following description and relate it to the wording of R1." The first bullet's text should be left-hand justified with the first line of the bullet's text. The bullet's first line should be hanging, not indented. Delete the comma after "and" in the first bullet. Insert in the following bullets the phrases that are in ALL CAPS o If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any, OCCURRING BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event. o If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any, OCCURRING BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value. Re page 8: In the second paragraph “entity(s)” should be “entity’s”. Re page 10, insert the phrase in ALL CAPS into: SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW) AND BEFORE OR WHEN ATTAINING THE MOST POSITIVE REPORTING ACE. The formulas should be replaced by the standard mathematical notation listed at http://www.robertblohm.com/BackgroundDocumentMath.doc and cross-referenced to the spreadsheet which does not allow standard mathematical notation.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE,

PA, PSE, RP, TO, TOP, TP, and TSP. Applicability Section: 4.1.1 needs clarification. It is unclear what "not in active status" means. Specifically, it is unclear whether a BA may be in "active status" by simply being under an RSG agreement and governing rules. It is unclear whether a BA not choosing to call on RSG assistance for any single Balancing Contingency Event (whether Reportable or not) would be considered "not in active status." This makes R2 unclear as to whether and when the BA is the Responsible Entity as well as what MSSC and reporting threshold would apply. PPL suggests the following language: A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only for the Reportable Balancing Contingency event(s) during which the Balancing Authority does not request assistance from the Reserve Sharing Group under the applicable agreement or governing rules for the Reserve Sharing Group. Rather than prescribe the commercial arrangements between members of a RSG, the above language respects whatever arrangements RSG members have put in place recognizing that these arrangements must enable the group and its members to remain in compliance with all applicable requirements. In R1, the revised language is still confusing. It is unclear how a Balancing Contingency Event can be both "subsequent" and "already occurred" to a Reportable Balancing Contingency Event. PPL cannot suggest a solution as we don't understand the intent of the added language. In R2, the calculation/evaluation of the 5 hour/quarter "exception clock" did not need elimination – it needed explanation. It is unclear whether the exception clock was to be evaluated as the average, mean or median of the Contingency Reserves held for a Clock Hour. M2 specifies a Clock Hour as the time increment to be used – Clock Hour should also be stated in R2. PPL suggests that the 5-hour exception clock be based on the Clock Hour average amount of Contingency Reserves held by the Responsible Entity (BA or RSG) for the calendar quarter. The elimination of the 5-hour exception clock and added requirement to maintain an hourly average amount of Contingency Reserve is not an improvement of R2. As the proposed standard is significantly different from the historical/existing DCS, a draft RSAW should be provided so Responsible Entities can have an indication of how compliance will be evaluated.
Group
SERC OC Review Group
Sammy Roberts
Yes
We would like to thank the SDT for their hard work and perseverance in developing this standard as well as the opportunity to provide comment. A) Requirement 1: Likewise, the changes made to Requirement 1, while adding to complexity, are positive changes. Additional clarity may be achieved by restructuring the requirement in tabular form with the simplest scenario listed first. B)Requirement 2: While we agree with the intent of Requirement 2, we continue to believe that the proposed language will have unintended consequences from the intended objective and could inject an unnecessary element into the Balancing Operator's decision making process. We believe R2 discourages a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Events of this type could include, but are not limited to, low ACE due to unexpected load changes, schedule changes, and/or slow unit response that are adversely affecting Interconnection frequency or transmission flows approaching IROL's due to contingencies that have occurred in an adjacent balancing area. Current R2 language: Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency. Recommended R2 language: Except during the Responsible Entity's Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity shall maintain an amount of Contingency Reserve, averaged over each Clock Hour, at least equal to its Most Severe Single Contingency ADD: ,averaged over each Clock Hour. C)We request the SDT to consider adding a sub-requirement to address the concern that R2 potentially could discourage a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Suggested R2.1 language follows: ADD: R2.1 Contingency reserves will be

restored within the 105 minute recovery + restoration periods following deployment of contingency reserves for a reliability need. D)The SDT is requested to consider developing a draft RSAW to accompany this draft standard. The OC Review Group feels it is critical to have the draft RSAW to go along with the draft standard. E)We respectfully request the SDT review the "averaged over each Clock Hour," when an event occurs within the last portion of the hour. The standard should include language that states that average hourly contingency reserves will not fall below average hourly MSSC for more than three consecutive clock hour. Summary: We believe that the suggested modifications above would allow Balancing Operators to utilize the appropriate resources at their disposal to mitigate events that may have an adverse impact on Interconnection reliability while establishing a continent-wide contingency reserve policy in accordance with Order 693 and avoiding increased costs to our customers. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Catherine Wesley
PJM Interconnection
Yes
PJM would like to thank the SDT for their hard work and perseverance in developing this standard as well as the opportunity to provide comment. The changes made to the definition of Reportable Balancing Contingency Event, while adding to complexity, are positive changes. However, due to the language in R1.3, the definitions need to clearly define and differentiate the start of the Balancing Contingency Event and the start of the Reportable Balancing Contingency Event compliance period. This differentiation is especially important for BCA's that may begin with a controlled unit runback but turn into an RBCA when the unit trips offline. Likewise, the changes made to Requirement 1, while adding to complexity, are positive changes. Additional clarity may be achieved by restructuring the requirement in tabular form with the simplest scenario listed first. While we agree with the intent of Requirement 2, we continue to believe that the proposed language will have unintended consequences from the intended objective and could inject an unnecessary element into the Balancing Operator's decision making process. We believe R2 discourages a Balancing Operator from deploying contingency reserves for events that may have an adverse impact on reliability but do not fall under the proposed definition of a Reportable Balancing Contingency Event nor occur during an EEA Level 2 or 3. Events of this type could include, but are not limited to, low ACE due to unexpected load changes, schedule changes, and/or slow unit response that are adversely affecting Interconnection frequency or transmission flows approaching IROL's due to contingencies that have occurred in an adjacent balancing area. If there was to be a commodity measure in the standard, there are changes to the current proposal that could relieve the aforementioned concerns. Proposal #1: The standard could include language that states that contingency reserves shall be restored within the 105 minute recovery + restoration periods following deployment of contingency reserves for a reliability need. Proposal #2: Alternatively, the standard could include language that states that average hourly contingency reserves shall not fall below average hourly MSSC for more than three consecutive clock hours. Regardless of which of these proposals are adopted, the hourly contingency reserves should be in reference to average hourly MSSC. This will add clarity for BA's that have a dynamic MSSC that changes in real-time. We believe that the suggested modifications above would allow Balancing Operators to utilize the appropriate resources at their disposal to mitigate events that may have an adverse impact on Interconnection reliability while establishing a continent-wide contingency reserve policy in accordance with Order 693 and avoiding increased costs to our customers.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
1) The current draft's definition and then practical inclusion of Most Severe Single Contingency, has retained the "MW output" term, yet now includes the concept of lost power import schedules. This "MW output" term worked fine when the original NERC Policy and then Standard addressed only loss

of Generation within a BA’s footprint. Because sudden cut of an import schedule is unlikely to result in a sudden decline in net energy export, AECI now seeks clarity for the “MW output” term’s meaning: 1a. Loss of net generation MW output (likely to be the common BA perception)?, OR 1b. Loss of MW output from the BA’s footprint, and disregarding scheduled interchange?, OR 1c. Algebraic decline of inadvertent interchange (Net-Actual-Interchange minus Net-Scheduled-Interchange), and disregarding Interchange frequency change?, OR 1d. Algebraic decline of ACE which typically includes the BA frequency-bias factor applied to any sudden frequency change? 2) This current draft of NERC Reliability Standard BAL-002-2’s requirements R1 and R2, in conjunction with EOP-003-2 R1, can cause BAs to unnecessarily shed load, or to be instructed by an RC to do so, when there is no real risk to BES reliability, and even when Interconnection frequency is quite high, in direct opposition to the more refined reliability-based BAL-001-2 Standard now awaiting FERC approval. See AECI’s suggestions #3 and #4. 3) Due to unintentional consequences, this current draft as well as its predecessors, has a serious scalability issue. Both large BAs and now large RSGs, necessarily provisioned to allow small BAs some equitable relief under BAL-002, allow and even encourage creation of artificially over-sized entities, to lower the business-related impact of the BAL-002 Standard yet: 1) at a potentially reduced value to overall BES reliability, should they get even larger, or 2) no real added-value to BES reliability for smaller BAs having been forced into RSGs or large Market –based BAs. So, unless BAL-002-2 is removed as a Reliability Standard altogether, AECI proposes two options for a simplified version of this standard, based upon our own experience of obligations within a reasonably sized RSG: 3a. 5% of each BA or RSG’s largest online unit’s capability, yet with consideration for multiple constricted areas within their footprint being held to the same metric. 3b. 0.8% of each BA’s or RSG’s net online generating capability, or net load, whichever is greater. (AECI favors this as being simple, close to what the large BAs and RSGs are carrying, and with added benefit of being dispersed within footprints containing smaller BAs.) 4) Draft BAL-002-2 is now fundamentally a fair business practices standard. All reliability-related issues historically addressed within BAL-002 predecessor’s requirements or guidelines, now appear to be better met by the overlapping effects of NERC Requirements found within EOP-001 (Adequate planning and provision for resources to weather the Most Severe Single Contingency event), BAL-001-2 (Ongoing degree of reliability-related Energy and Frequency Imbalance), and BAL-003 (Frequency-response reflecting amount of Spinning-reserve being carried). This explains why SDT Requirement R2 consideration to allow for up to 5 “failing” hours within a calendar month, was refuted by argument that such allowance could be abused by Entities deliberately coinciding their deficiencies with peak-hours, a fair business-practice argument, but then countered by BAL-001-2's essentially precluding such behavior. So BAL-002-2 is now a candidate for NASB adoption, as they deem necessary, with removal from the BAL standards. 5) Provided this SDT elects to not entirely remove BAL-002-2 from the NERC Reliability Standard set or simplify per Options 3a or 3b above, AECI does favor the SERC OC WG's suggested addition of ", averaged over each Clock Hour" to then end of R2, as well as R2.1, as well as their part "E)" suggestion for allowing reserves to drop below MSSC for no more than three consecutive clock hours. Due to current draft complexities, AECI also favors an RSAW being developed by the SDT ASAP.
Group
DTE Electric
Kathleen Black
Agree
MISO
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) The addition of Part 1.3 clarifies that the requirement does not apply when the contingency exceeds its Most Severe Single Contingency (MSSC). Its inclusion obviates the need for the second sub-bullets of R1 under the first and second main sub-bullets and that begins with “Further reduced by the magnitude…” These sub-bullets are not needed because they only apply when the Balancing Contingency Event exceeds the MSSC and Part 1.3 is clear that the main requirement does not apply in this situation. (2) We continue to believe that the thresholds established in the Reportable

Balancing Contingency Events are arbitrary. There is no supporting evidence for the values that were selected. The companion background document does include a brief discussion of the thresholds but it only discusses why 100 MW was not selected and it does not discuss why the thresholds were selected. What is the justification that the threshold for the Eastern Interconnection cannot be above 900 MW for example? (3) The Reportable Balancing Contingency Event definition is fundamentally flawed. The last sentence contradicts the statement that the lower threshold is 80%. The lower threshold is in fact no greater than 80% and is set by the responsible entity upon written notification to the Regional Entity. If the value will be variable, this should be stated directly in the first sentence of the requirement to avoid the definition contradicting itself. (4) The Reportable Balancing Contingency Event definition should be further modified to avoid unnecessary compliance burdens and paperwork. There is no need to notify the Regional Entity in writing before changing the lower reporting threshold. The Regional Entity has no documented process in the standard to prevent the change from occurring so communicating it to the Regional Entity is an unnecessary compliance burden. The responsible entity should only be obligated to document it. The Rules of Procedure allow the Regional Entity to request this type of data in several other ways. They could even request it as part of an annual self-certification as an example. FERC has stated that definitions are considered standards, and this part of the definition could be viewed as meeting Paragraph 81 criteria because it is administrative in nature. In particular, it meets criterion B4 because it requires reporting to the Regional Entity which has “no discernible impact on promoting the reliable operation of the BES.” (5) The definition of Pre-Reporting Contingency Event ACE Value requires additional justification to change the pre-disturbance calculation from an average of 10 to 60 seconds of ACE data prior to the disturbance to a 16-second interval. There is no explanation of this in the background document and we cannot support such a change without a justification for how it supports reliability. Furthermore, the definition is not consistent with other reliability standards, such as BAL-005-0.2b which requires ACE calculation on at least a six-second basis. A BA using a six-second sample rate could be viewed as being out of compliance if an entity used either two (12 seconds) or three (18 seconds) samples since they cannot use exactly 16 seconds of data. Furthermore, using only two or three samples could lead to unrealistic averages particularly if there are any spurious data points. What does an entity do if a scan was skipped or there was a data spike? More samples would make it less likely for this to be an issue. (6) While the standard has been modified to provide more flexibility in the use of Contingency Reserve, there still is not enough flexibility and the standard could have unintended consequences for reliability. For example, the definition of Contingency Reserve limits the use of Contingency Reserve to only contingent events. This would prevent the BA from using Contingency Reserve for other reliability purposes such as to respond to inadequate schedule ramping when other units don’t ramp as expected. A BA should be free to call upon Contingency Reserve to reduce a negative ACE for reliability support regardless of whether it is caused by a contingency or some other event. (7) The “Additional Compliance Section” potentially conflicts with the definition of Contingency Reserve. Since “Additional Compliance Section” would allow the use of Contingency Reserve to meet other standards as required this would be a conflict if the use of Contingency Reserve was to comply with another standard not involving a contingency. The definition of Contingency Reserve restricts the use to only contingencies. For example, the IRO-005-3.1a R5 compels the BA to utilize all resources to relieve emergency conditions regardless of whether they were caused by a contingency or not. (8) The data retention required for the current versions of this standard is too long. BAs submit quarterly data to their regional entities, so they should not be required to retain three years worth of data. While the standard will no longer compel this quarterly reporting, this practice is unlikely to change. At the very least, compliance staff should be consulted to determine if this will continue to be the practice. We strongly recommend the drafting team collaborate with NERC compliance to develop an RSAW and other compliance guidance. If the RSAW was developed with the standard, it would facilitate the discussion with industry of how much data is needed to be retained. (9) The data retention section of the standard exceeds what is allowed in the NERC Rules of Procedure, Section 3.1.4.2 of Appendix 4C. This section specifies that “the audit period begins the day after the End Date of the prior Compliance Audit...the audit period will not begin prior to the End Date of the previous Compliance Audit.” Since BAs are only audited approximately every three years, the data retention period of up to four years (current year, plus three previous calendar years) exceeds the three year audit period. (10) Thank you for the opportunity to comment.
Individual
Gregory Campoli

New York Independent System Operator
Agree
The NYISO supports the comments and questions raised by both the IRC/SRC and NPCC RSC.
Group
SPP Standards Review Group
Robert Rhodes
Yes
In BAL-002-2: We would like to thank the drafting team for the clarification provided in the definition of Reportable Balancing Contingency Event regarding the intent of ‘sudden’. We also thank the drafting team for adding the clarification on events larger than an entity’s MSSC as provided in Requirement R1.3. In the Background Document: On Page 5, in the 3rd line of the 2nd paragraph under Contingency Reserve, change ‘complimented’ to ‘compliment’. In the 6th line of the same paragraph, capitalize ‘reserve’ in ‘Operating Reserve’. On Page 11, in the 10th line of the 2nd paragraph under the Background and Rationale section for Requirement 2, delete the ‘s’ on ‘suites’. In the last line of the last paragraph on Page 11, replace ‘real-time’ with ‘Real-time.’ In the CR Form 1: Replace ‘Exemp’ with ‘Exempt’ in the title on the Exemption worksheet. Use of terms: Demand-Side Management – In the definition of Contingency Reserve in the standard and in the Contingency Reserve section of the Background Document, use the NERC Glossary of Terms Demand-Side Management in lieu of Demand Side Management. Clock Hour – In Measure M2, be consistent with the use of Clock Hour. In some uses the term is capitalized and in others it isn’t.
Individual
Russel Mountjoy
Midwest Reliability Organization
Agree
Midcontinent Independent System Operator (MISO)
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Agree
Duke Energy
Individual
Richard Vine
California ISO
Agree
ISO/RTO Standards Review Committee
Group
Bonneville Power Administration
Jamison Dye
Yes
- Definition R1 refers to ‘Reporting ACE’ and there is no accompanying definition of this term. - BPA recommends further clarity and explanation for the sudden unplanned outage of a transmission facility, and sudden restoration of known load used as a resource that causes an unexpected change to responsible entity’s ACE. - BPA recommends leaving in the Unexpected Failure of Generation to start language in the definitions section.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No

ERCOT ISO is generally supportive of the IRC SRC comments, the BAL-002-2 standard, and appreciates the work the SDT has done on the standard and the opportunity to comment. ERCOT ISO suggests that the 800 MW threshold for ERCOT be removed from the definition of Reportable Balancing Contingency Event for the ERCOT single-BA area Interconnection and have the calculation of MSSC apply to single-BA area Interconnections.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-002-2)

Additional Ballot and Non-Binding Poll Now Open through December 11, 2013

Now Available

An additional ballot and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for **BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern on Wednesday, December 11, 2013**.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results for 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 final 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 (via email), Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves (BAL-002-2)

Formal Comment Period: October 28, 2013 – December 11, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: December 2-11, 2013

Now Available

A formal comment period for **BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern on Wednesday, December 11, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for the standard is open through **8 p.m. Eastern on Wednesday, December 11, 2013**. Please use the electronic comment form to submit comments.

An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **Monday, December 2, 2013** through **8 p.m. Eastern on Wednesday, December 11, 2013.**

Standards Development Process

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Standards Announcement

Project 2010-14.1 Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **BAL-002-2- Contingency Reserve for Recovery from a Balancing Contingency Event** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, December 11, 2013.**

Voting statistics for the additional ballot are listed below, and the Ballot Results page provides a link to the detailed results. This standard achieved a quorum but did not receive sufficient affirmative votes for approval.

Approval	Non-Binding Poll Results
Quorum: 75.29% Approval: 64.24%	Quorum: 76.62% Supportive Opinions: 66.67%

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 standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development 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.

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Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-002-2
Ballot Period:	12/2/2013 - 12/11/2013
Ballot Type:	Additional Ballot
Total # Votes:	262
Total Ballot Pool:	348
Quorum:	**75.29 % The Quorum has been reached**
Weighted Segment Vote:	64.24 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	90	1	34	0.531	30	0.469	0	7	19
2 - Segment 2	10	0.9	6	0.6	3	0.3	0	0	1
3 - Segment 3	79	1	31	0.574	23	0.426	0	4	21
4 - Segment 4	24	1	11	0.733	4	0.267	0	3	6
5 - Segment 5	73	1	32	0.627	19	0.373	0	2	20
6 - Segment 6	53	1	26	0.667	13	0.333	0	1	13
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	6	0.3	3	0.3	0	0	0	1	2
9 - Segment 9	3	0.1	0	0	1	0.1	0	0	2
10 - Segment 10	8	0.6	4	0.4	2	0.2	0	2	0
Totals	**348**	**6.9**	**147**	**4.432**	**95**	**2.468**	**0**	**20**	**86**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Central Electric Power Cooperative	Michael B Bax		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO, Marie Knox)
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion supports PJM's comments for this ballot)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra/FPL)
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
				SUPPORTS

1	KAMO Electric Cooperative	Walter Kenyon	Negative	THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)- MISO - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO & MRO NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection LLC)
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL

				NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Concur with PJM comments.)
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	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	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	COMMENT RECEIVED
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	APS	Steven Norris		
				SUPPORTS THIRD PARTY

3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	COMMENTS - (See AECI comments)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection LLC)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection LLC)
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion supports PJMs comments.)
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Entergy)
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey		
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell		
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		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand		
3	Mississippi Power	Jeff Franklin		
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)MISO - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support MISO's comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection LLC)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)

3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
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	Affirmative	
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	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO comments)
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
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	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
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	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM's Comments)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego		
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)MISO - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
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		
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
				SUPPORTS THIRD PARTY

5	PPL Generation LLC	Annette M Bannon	Negative	COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
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	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Florida)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
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		
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban		
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion supports PJMs comments.)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports PJM

				Comments)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)MISO - (MRO NSRF)
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		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
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	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Florida)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist		
7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz	Affirmative	
8		Robert Blohm	Affirmative	
8		Edward C Stein		
8	Debra R Warner	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	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and ISO-NE)
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Negative	COMMENT RECEIVED -SERC
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy

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Account Log-In/Register

Non-Binding Poll Results

Project 2010-14.1 BAL-002-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-14.1 BARC BAL-002-2
Poll Period:	12/2/2013 - 12/12/2013
Total # Opinions:	249
Total Ballot Pool:	325
Ballot Results:	76.62% of those who registered to participate provided an opinion or an abstention; 66.67% 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	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO, Marie Knox)
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Duke Energy)
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
1	Florida Power & Light Co.	Mike O'Neil	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra/FPL)
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(AECI)
1	National Grid USA	Michael Jones	Abstain	
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	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO & MRO NSRF)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
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	Affirmative	
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	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (SERC OC Review group)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
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	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Negative	COMMENT RECEIVED
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
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		
3	APS	Steven Norris		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (See AECI Comments)
3	Avista Corp.	Scott J Kinney	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	

3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Entergy)
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports PJM comments)
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Danny Lindsey		
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell		
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		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Mississippi Power	Jeff Franklin		
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Abstain	

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3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
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	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	

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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
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	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
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	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM's Comments)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
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		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brian Murphy)

5	Northern Indiana Public Service Co.	William O. Thompson	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
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		
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
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	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Florida)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
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	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports PJM Comments)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (NextEra)
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO SRF)
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		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

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	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy Florida)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist		
7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz	Affirmative	
8		Robert Blohm	Affirmative	
8		Edward C Stein		
8	Debra R Warner	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	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and ISO-NE)
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

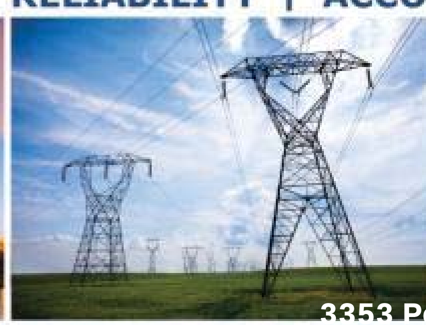
Consideration of Comments Summary

Project 2010-14.1 BARC – Reserves
BAL-002-2

August 2014

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2010-14.1 Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-002-2 The standard was posted for a 45-day formal comment period from October 28, 2013 through December 11, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 32 sets of responses, including comments from approximately 90 different people from approximately 70 companies representing all 10 Industry Segments..

All comments submitted may be reviewed in their original format on the 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 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

Consideration of Comments

Purpose

The BARC Standard Drafting Team (SDT) appreciates industry's comments on the BAL-002-2 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if an additional comment period and ballot are needed. The following pages are a summary of the comments received and how the SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer to discuss.

NERC Glossary Term "Reportable Balancing Contingency Event"

Some commenters questioned the need for this term. The SDT is addressing a FERC directive to create a continent wide Contingency Reserve Policy. The SDT believes that the first step in creating this policy is to define what would constitute a reportable event. The SDT believes it is addressing the directive by defining what constitutes a reportable event. The SDT also points to the request made by the Northwest Power Pool for an interpretation of BAL-002-1 currently pending at FERC in Docket No. RM-13-6-000. The interpretation was requested to provide clarity as to what constituted a Disturbance Control Standard (DCS) event and if a BA was to be held compliant for an event greater than its MSSC.

A small number of commenters expressed confusion about when a Reportable Balancing Contingency Event begins or when a Balancing Contingency Event could become a Reportable Balancing Contingency Event. The SDT addressed this concern within the definition of a Reportable Balancing Contingency Event, with the phrase "occurring within a one minute interval of the initial sudden decline in ACE based on EMS scan rate data." For example, if a Balancing Authority's (BA) Most Severe Single Contingency (MSSC) is 500 MW, then 80% of 500 MW yields a 400 MW change that must be observed within a sliding one minute interval in the output of the resource lost in order to qualify as a Reportable Balancing Contingency Event. When the output of the resource lost meets this criterion, the first occurrence of a decline in the lost resource's output observed within the EMS scan rate data within that sliding one minute interval demarcates the start of the event.

Definitions

One commenter questioned why Reporting ACE was not listed in the definitions. The term was removed from BAL-002-2 since it had been approved by the industry and adopted by the NERC BOT during the development of BAL-001-2.

Applicability Section

Some commenters questioned why the Applicability was on an event by event basis. The SDT is aware of RSGs that allow a BA to participate as a member of the RSG or to respond to an event without activation of the RSG. Since some RSGs allow for this to occur, the SDT feels that the language is appropriate and should be included in the applicability section.

One commenter appeared confused as to who could activate Contingency Reserves. They believed that BAL-002-2 was allowing for a Frequency Response Sharing Group (FRSG) to deploy Contingency Reserve. BAL-002-2 does not provide for this to happen. This standard only provides for Contingency Reserves to be deployed for Balancing Contingency Events and Reportable Balancing Contingency Events.

Another commenter questioned what the SDT meant by use of the term "active status". The SDT believes that this term provides sufficient clarity and that those BA's and RSG's that allow for a BA to either use the RSG to recover from an event or recover from the event on their own understand the use of the term.

Energy Emergency Alert Level 2 or Level 3

A couple of commenters disagreed with the SDT using the terms Energy Emergency Alert Level 2 or Level 3. The SDT is attempting to correct the present inconsistency between BAL-002 and EOP-002. The SDT has identified the problem that if a BA is operating under either an Energy Emergency Alert Level 2 or Level 3 it would have deployed its reserves but would still be held compliant with the present BAL-002-1. However, the SDT believed that there could be issues arising from defining a specific alert level. The SDT modified the language to provide additional clarity and removed any reference to a specific alert level.

Another commenter believed that BAL-002-2 was directing a BA to shed firm load. BAL-002-2 does not have any language in it which mentions shedding load, either firm or interruptible. The SDT believes that shedding of load, either firm or interruptible, is an issue that must be addressed in the EOP standards.

Requirement R1

The SDT made some minor clarifying modifications to the requirement.

A few commenters said that the language in Requirement R1 was too complex and hard to understand. The SDT is correcting problems inherent in the current standard, which erroneously establish some requirements within the compliance elements of the standard. By moving the requirements language from the compliance elements into the requirements, the SDT believes that it more properly addresses instances regarding events that may be greater than MSSC. However, the SDT agreed that the language could be confusing as it was initially written. The SDT modified the requirement and removed some of the confusing language to provide additional clarity. The SDT has also provided CR Form 1 to assist Bas in calculating its compliance with a Reportable Balancing Contingency Event.

Some of the commenters felt that the use of the terms “subsequent” and “already occurred” created confusion within the requirement. The SDT agreed and has removed these terms.

A couple of commenters were confused as to why CR Form 1 was not attached to the standard. The CR Form 1 will be attached to the standard once the standard is approved by the industry and prior to filing with FERC.

The SDT added Requirement R1 part 1.3 to clearly identify that a BA would not be held compliant with Requirement R1 when its Reportable Balancing Contingency Event exceeded its MSSC during the Contingency Event Recovery Period or its Contingency Reserve Restoration Period. The 105 minute timeframe referenced in this requirement is simply the combination of the 15 minute Contingency Event Recovery Period and the 90 minute Contingency Reserve Restoration Period. These time periods have been in use for many years by the industry and the SDT did not see any reason to modify them.

One commenter stated that the draft standard was requiring deployment of reserves for any and all events. The SDT disagrees with the commenters concern. The current draft of the standard does not require the deployment of reserve for anything other than a Reportable Balancing Contingency Event. The SDT has added language in the Additional Compliance section and in Requirement R2 that allows a BA to deploy reserves for events other than a Reportable Balancing Contingency Event but does not require this to be done.

Another commenter wanted the SDT to modify the requirement to use the term “shall” in parts 1.1, 1.2 and 1.3. The SDT discussed this but did not see any advantage to using this term over what is presently used in the standard.

Requirement R2

Several commenters did not believe that Requirement R2 was necessary. The SDT disagrees and believes the requirement is necessary for reliability and to meet the approach for the FERC directive. The current standard (Requirement R3 part 3.1) requires a BA or RSG to maintain Contingency Reserve at least equal to its MSSC.

A couple of commenters felt that this requirement was too restrictive in that it did allow for use of Contingency Reserve for anything other than a Reportable Balancing Contingency Event. Although the SDT had added language in the Additional Compliance Information section to allow for this to occur it was still not clearly stated that an entity would not be penalized for being below its MSSC during these events. The SDT added language in Requirement R2 to clearly state that an entity could deploy Contingency Reserve for events other than reportable events.

A few commenters believed that there was a problem with the use of the term “averaged over each Clock Hour”. The SDT agreed and modified the language to reflect averaging for both reserves and MSSC.

Another commenter felt that the structure of the requirement created confusion. The SDT agreed and modified the requirement to provide clarity.

A couple of commenters disagreed with removing the five hour exemption from Requirement R2. The SDT removed the five hour exemption because they could not develop a sufficient argument to allow a BA to be deficient and not have its MSSC at all times other than during the times when the Contingency Reserve was being deployed or when the BA is operating during the Contingency Event Recovery Period or the Contingency Reserve Restoration Period given that the present standard does not allow for any such exemption. However, the SDT did add language in the requirement to allow for Contingency Reserves to be deployed for events other than reportable events.

Measure M2

One commenter stated that they felt the Measure M2 was written as more of an exemption rather than a measure. The SDT added the language to the measure for Requirement R2 to identify when data would be excluded from the calculation of Contingency Reserve. The SDT modified the language to provide additional clarity.

Violation Severity Levels (VSLs)

There were a couple of comments regarding concerns with the VSLs. All VSLs have been reviewed and modified as necessary to ensure proper alignment with the requirements.

One commenter felt that the VSL for Requirement R1 should have something to account for an entity not using CR Form 1. If an entity does not provide the information on CR Form 1 then the entity would be deemed to have not responded to the event and therefore would be at a Severe VSL.

Quarterly Compliance

The only DCS quarterly performance reporting is for Requirement 3 of presently existing Reliability Standard BAL-002-1, which says “Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.” There are 2 additional requirements, R4 and R5, which have immediate compliance implications. Requirement 4 states “A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances.” This is an immediate measure of a BA’s ability to return its Area Control Error (ACE) to pre-disturbance ACE or zero depending on the pre-disturbance. Requirement 5 states “Each Reserve Sharing Group shall comply with the DCS.” A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members, and makes no mention of quarterly compliance. The same is true for Requirement 4; therefore, it is also subject to immediate compliance.

The Disturbance Recovery Criterion is calculated for each event and reported on a quarterly basis; however, such events are relatively rare and there may be one or less such events in a given quarter. Many of the significant events in NERC which involved unit tripping have resulted in the responsible entity paying a fine for failure to comply with BAL-002. Therefore it is necessary to clarify that DCS compliance is based on an event-by-event basis and not on a quarterly basis. DCS recovery is not a long term measure and a quarterly measure could send the wrong signal to the responsible entity.

The newly proposed BAL-002 no longer includes a provision for increasing the amount of contingency reserves as a part of the penalty for non-compliance. In fact, the increasing of contingency reserves is not now part of what NERC would impose as a penalty. In addition, the increases in contingency reserves associated with non-compliance most likely would result in a much bigger monetary consequence than the sanction/fine that would be imposed by NERC. Since increasing Contingency Reserves is no longer part of the penalty, using a quarterly measure to determine an average failure makes little sense. As soon as a responsible entity fails to comply with DCS requirements for an event, they will fail for the quarter. If that failure were to occur early in the quarter, there could be exposure to additional penalties since it may be non-compliant for up to 90 days since the failure before the determination of the quarterly measure is made.

New NERC standards typically use a report by exception instead of continuous reporting scheme. The proposed BAL-002 does not include a reporting requirement. The SDT provides a statement of the required performance (what is required) and the CR Form 1 to use in determining compliance. If a responsible entity determines it was non-compliant for a reportable event, they are expected to self-report, similar to any other discovery of non-compliance. A failure to self-report could result in the non-compliance being discovered at the next audit of the entity, with exposure to many days of non-compliance.

Background Document

The SDT modified the BAL-002-2 Background Document to provide rationale for excluding events greater than a BA's MSSC.

One entity questioned how the SDT developed the reporting thresholds. This is discussed on pages 8 and 9 of the Background Document and the graphs are shown in Attachment 1 of the Background Document.

Reliability Standard Audit Worksheet (RSAW)

The SDT received comments requesting a Reliability Standards Audit Worksheet (RSAW). The RSAW was developed and posted to the project page.

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 Control, 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.
8. The draft standard was posted for 30-day formal industry comment period from June 4, 2012 through July 3, 2012.
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Proposed Action Plan and Description of Current Draft:

This is the fifth posting of the proposed standard. This proposed draft standard will be posted for a 45-day formal comment period and 10-day successive ballot.

Future Development Plan:

Anticipated Actions	Anticipated Date

1. Fifth posting	August/September 2014
2. Successive Ballot	September 2014
3. Final Ballot	October 2014
4. NERC BOT adoption.	November 2014

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 Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
    a. Due to
        i. Unit tripping,
        ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
        iii. Sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated.

4.1. Responsible Entity

4.1.1 Balancing Authority

4.1.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.1.2 Reserve Sharing Group

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

5.1. The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees' or as otherwise provided for in that jurisdiction.

B. Requirements

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any

Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or,

- o Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3 Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105 minute period.

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or
- a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or
- an Energy Emergency Alert Level under which Contingency Reserves have been activated.

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, or dated documentation that demonstrates compliance with Requirement 1.2 and 1.3.

M2. Each Responsible Entity shall have dated documentation that demonstrates compliance with Requirement R2, evidence of compliance may include, but is not limited to, documenting Contingencies through outage records, an Energy Emergency Alert Level under which Contingency Reserves have been activated with communication from their RC, operator logs, and others.

If the recording of Contingency Reserve or MSSC is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule (restoration period following a Contingency which is not a Balancing Contingency Event, an Energy Emergency Alert Level under which Contingency Reserves have been activated, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered 70% or less of required recovery during the Contingency Event Recovery Period.
R2	The Responsible Entity had Contingency Reserve but the Clock Hour average amount	The Responsible Entity had Contingency Reserve but the Clock Hour average amount	The Responsible Entity had Contingency Reserve but the Clock Hour average amount	The Responsible Entity did not have Contingency Reserve that was equal to or

	of Contingency Reserve was less than 100% of MSSC but was greater than or equal to 90% of MSSC as averaged over the Clock Hour.	of Contingency Reserve was less than 90% of MSSC but was greater than or equal to 80% of MSSC as averaged over the Clock Hour.	of Contingency Reserve was less than 80% of MSSC but was greater than or equal to 70% of MSSC as averaged over the Clock Hour.	greater than 70% of MSSC averaged over the Clock Hour.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

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    a. Due to
        i. Unit tripping,
        ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
        iii. Sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts ~~Level 2 or Level 3~~ as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

A. Introduction

1. **Title: Disturbance Control Performance - Contingency Reserve for Recovery From a Balancing Contingency Event**

2. **Number: BAL-002-2**

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the~~this standard does not apply to a~~ Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated~~2 or Level 3~~.

4.1. Responsible Entity

4.1.1 Balancing Authority

4.1.1.1 A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

4.1.2 Reserve Sharing Group

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

5.1. The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees' or as otherwise provided for in that jurisdiction.

B. Requirements

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however,~~:~~

- o ~~less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred~~ during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,.~~, and~~

- ~~o~~ o~~further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC,~~

~~O~~r,

~~•~~ Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, ~~,~~

- o ~~less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred~~ during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.~~, and~~

- ~~o further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC.~~

1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A~~Requirement R1 (in its entirety) does not apply when the~~ Responsible Entity is not subject to compliance with Requirement R1 when it ~~experiencing a Reportable Balancing Contingency Event~~ is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated~~2 or Level 3~~.

1.3 Requirement R1 (in its entirety) does not apply~~when the Responsible Entity experiences~~~~experienc~~es:

- (i~~i~~) when the Responsible Entity experiences a~~n~~ Balancing Contingency Event that exceeds~~ing~~ its Most Severe Single Contingency, or

~~(ii) Balancing Contingency Events for which the sum of the resource output loss plus the sum of Contingency Reserves lost within a~~

~~Contingency Event Recovery Period exceeds its Most Severe Single Contingency for those events that occur within that 15 minute period, or~~

- (i~~ii~~i) after multiple Balancing Contingency Events for which the combined magnitude~~resource output loss plus the sum of Contingency Reserves lost within a Contingency Event Recovery Period~~ ~~whose sum~~ exceeds the Responsible Entity's~~its~~ Most Severe Single Contingency ~~within a 15 minute period~~ for those events that occur within a~~that~~ 10~~5~~ minute period.~~, or.~~

~~(iv) Balancing Contingency Requirement R1 also shall not apply to subsequent eEvents beyond athe Contingency Event Recovery Period15 minute period but within a Contingency Reserve Restoration Period105 minutes of the first Balancing Contingency Event if the sum of the resource output loss plus the sum of Contingency Reserves lost within a Contingency Event Recovery Periodevents exceeds the Responsible Entity's Most Severe Single Contingency.~~

R2. ~~Except during t~~The Responsible Entity~~'s Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity~~ shall maintain ~~an amount of~~ Contingency Reserve, averaged over each Clock Hour, greater than or~~at least~~ equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in:~~.~~ *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or
- a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or
- an Energy Emergency Alert Level under which Contingency Reserves have been activated~~2 or 3~~.

C. Measures

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, or dated documentation that demonstrates compliance with Requirement 1.2 and 1.3.

~~and additional documentation of any Balancing Contingency Event that has not completed its Contingency Reserve Restoration Period and that is used to reduce the recovery to the amount limited by MSSC.~~

M2. Each Responsible Entity shall have dated documentation that demonstrates compliance ~~its Contingency Reserve, averaged over each Clock Hour, was maintained in accordance~~ with Requirement R2, evidence of compliance may include, but is not limited to, documenting Contingencies through outage records, an Energy Emergency Alert Level under which Contingency Reserves have been activated~~EEA 2 and 3~~ with communication from their RC, operator logs, and others.~~.~~

If the recording of Contingency Reserve or MSSC is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule (restoration period following a Contingency which is not a Balancing Contingency Event, an Energy Emergency Alert Level under which Contingency Reserves have been activated~~EEA 2 overlap, EEA 3 overlap~~, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation.

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.

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 Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated~~2 or Level 3~~.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered less than 100% but more than 90% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 90% or less but more than 80% of required recovery.	The Responsible Entity recovered partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered 80% or less but more than 70% of required recovery.	The Responsible Entity recovered 70% or less of required recovery during the Contingency Event Recovery Period.
R2	The Responsible Entity had Contingency Reserve but the	The Responsible Entity had Contingency Reserve but the	The Responsible Entity had Contingency Reserve but the	The Responsible Entity did not have Contingency

	Clock Hour average amount of Contingency Reserve was less than 100% of MSSC but was greater than or equal to 90% of MSSC as averaged over the Clock Hour.	Clock Hour average amount of Contingency Reserve was less than 90% of MSSC but was greater than or equal to 80% of MSSC as averaged over the Clock Hour.	Clock Hour average amount of Contingency Reserve was less than 80% of MSSC but was greater than or equal to 70% of MSSC as averaged over the Clock Hour.	Reserve that was equal to or greater than 70% of MSSC averaged over the Clock Hour.

E. Regional Variances

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

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Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16 second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard ~~Level 2 or Level 3~~). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event. Comments must be submitted using the electronic comment form by 8 p.m. **October 2, 2014.** If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

Background Information:

Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard.

- Modified the Applicability to provide additional clarity.
- Modified Requirement R1 to provide additional clarity.
- Modified Requirement R2 to provide additional clarity and allow for the use of Contingency Reserve for other than a Balancing Contingency Event.
- Modified the BAL-002-2 Background Document to provide additional clarity.

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. **Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.**

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

BAL-002-2
Background Document

August 2014

RELIABILITY | ACCOUNTABILIT




Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. The suite of NERC Standard work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard, (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL will allow the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 will require the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may require the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances that could cause transmission overloads if certain units (typically N-1-1 or greater) were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there have been 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. When evaluating the data, events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, without regard to the size of a Balancing Authority or RSG and without respect to the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity if they have more stringent standards which require contingency reserve greater than MSSC.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, it is impossible for this event to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is primarily focused on generation and not Demand Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and compliment each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating Reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event. Without incurring a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- Zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative): however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3 Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within that 105 minute period. .

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance. The drafting team has included Attachment 2 illustrating an example of the calculation for Requirement R1.

In addition, the standard drafting team (SDT) through R1 parts 1.2 and R1.3 has clearly identified when R1 is not applicable. By including R1 part 1.2, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. A fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of the FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- The measured contingency reserve response is equal to one of the following:
    - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
    - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing

Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

Requirement 2

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in:

- a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or
- a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or
- an Energy Emergency Alert Level under which Contingency Reserves have been activated.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. Additionally, the drafting team understands that the Responsible Entity's available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying the operators' hands by removing the use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for other issues than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve for only other Contingencies, thus bounding the use of Contingency Reserve to only the N-1 conditions.

Attachment 1

NERC Interconnections 2009-2013

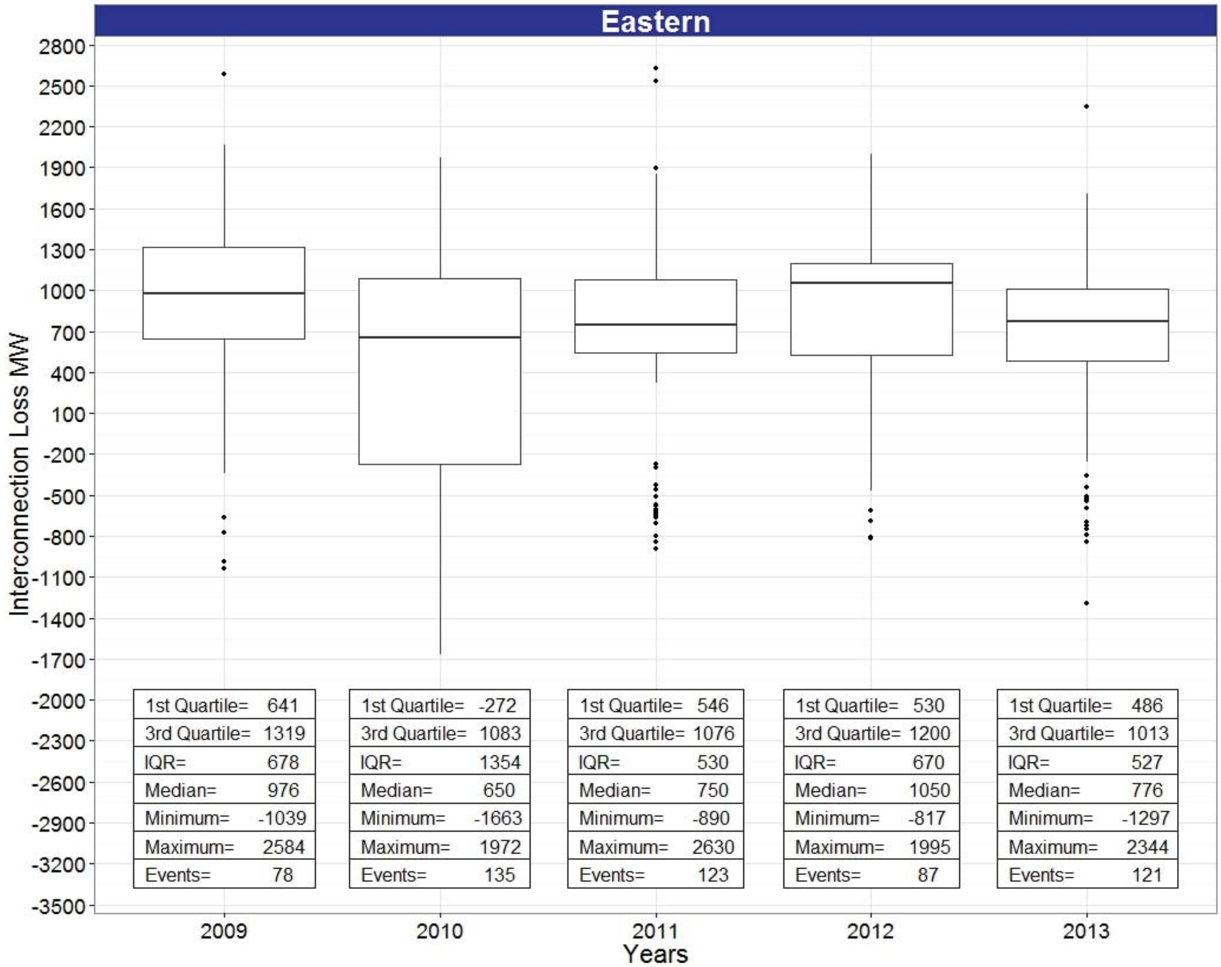
Frequency Events Loss MW Statistics

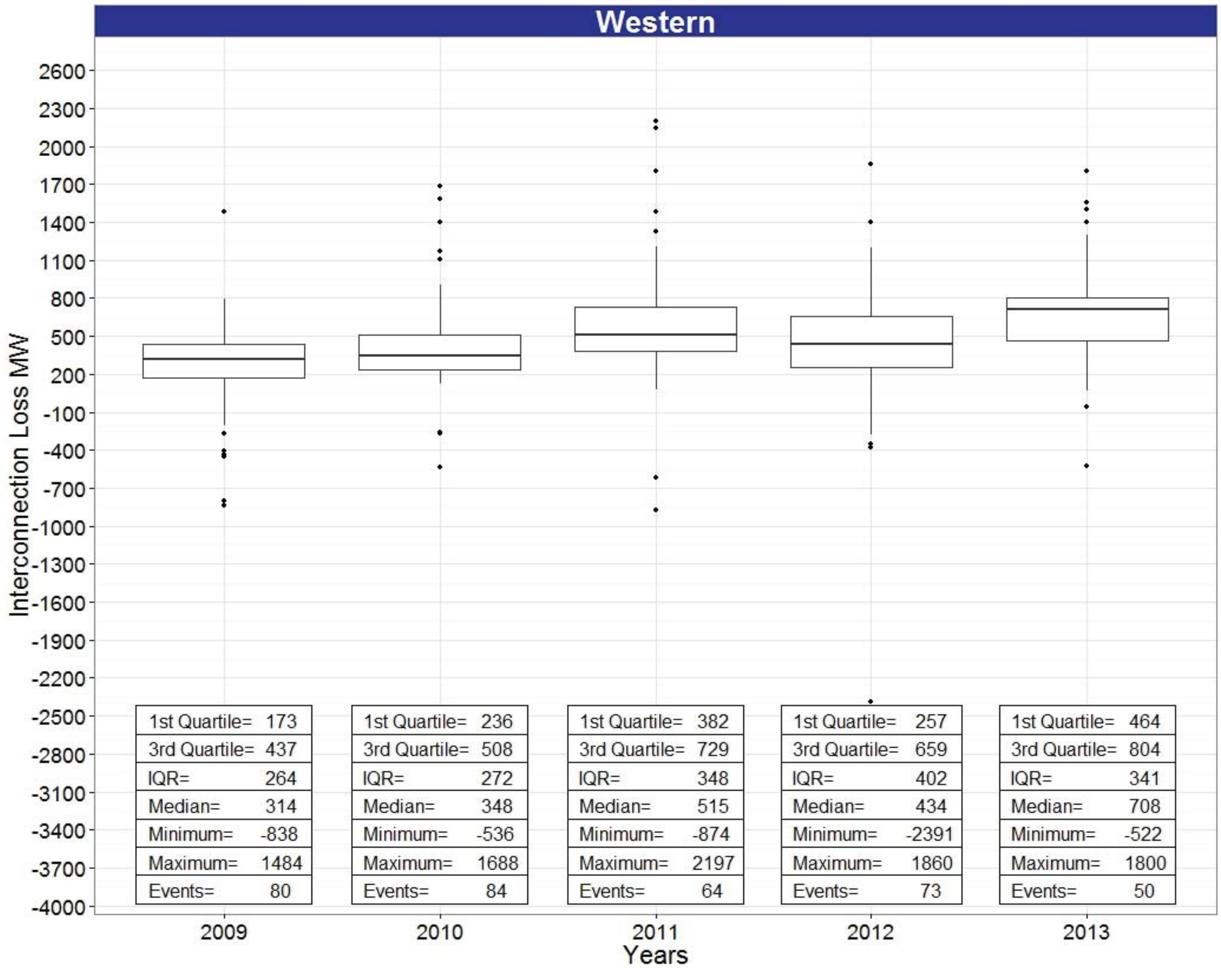
For: NERC BARC Standard Drafting Team

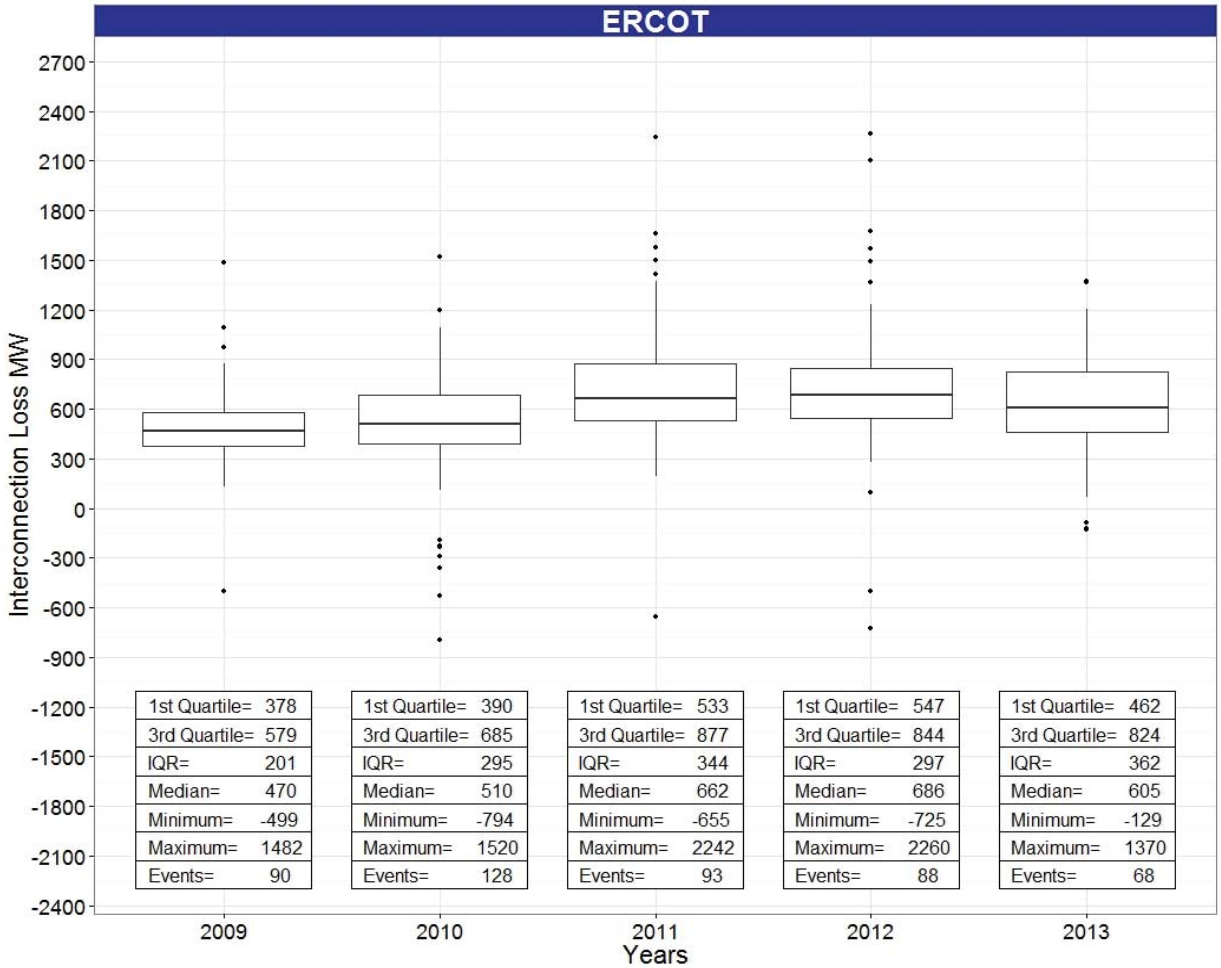
Prepared by: CERTS

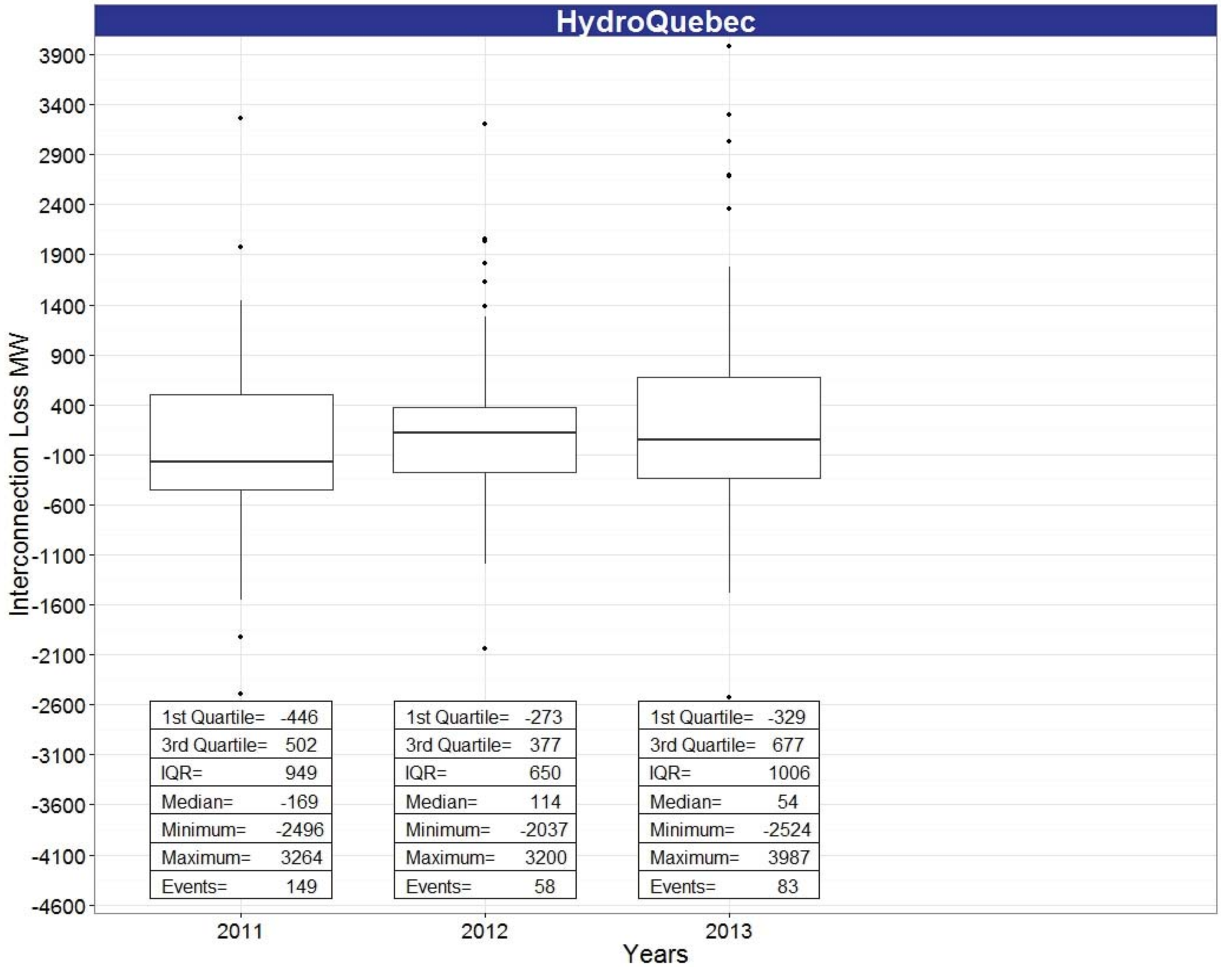
Date: October 15, 2013

CERTS
Consortium for Electric Reliability Technology Solutions


Eastern
2800
2500
2200
1900
1600
1300
1000
700
400
100
-200
-500
-800
-1100
-1400
-1700
-2000
-2300
-2600
-2900
-3200
-3500
Interconnection Loss MW
1st Quartile= 641
3rd Quartile= 1319
IQR= 678
Median= 976
Minimum= -1039
Maximum= 2584
Events= 78
1st Quartile= -272
3rd Quartile= 1083
IQR= 1354
Median= 650
Minimum= -1663
Maximum= 1972
Events= 135
1st Quartile= 546
3rd Quartile= 1076
IQR= 530
Median= 750
Minimum= -890
Maximum= 2630
Events= 123
1st Quartile= 530
3rd Quartile= 1200
IQR= 670
Median= 1050
Minimum= -817
Maximum= 1995
Events= 87
1st Quartile= 486
3rd Quartile= 1013
IQR= 527
Median= 776
Minimum= -1297
Maximum= 2344
Events= 121
2009
2010
2011
2012
2013
Years


Western
Interconnection Loss MW
2600
2300
2000
1700
1400
1100
800
500
200
-100
-400
-700
-1000
-1300
-1600
-1900
-2200
-2500
-2800
-3100
-3400
-3700
-4000
1st Quartile= 173
3rd Quartile= 437
IQR= 264
Median= 314
Minimum= -838
Maximum= 1484
Events= 80
1st Quartile= 236
3rd Quartile= 508
IQR= 272
Median= 348
Minimum= -536
Maximum= 1688
Events= 84
1st Quartile= 382
3rd Quartile= 729
IQR= 348
Median= 515
Minimum= -874
Maximum= 2197
Events= 64
1st Quartile= 257
3rd Quartile= 659
IQR= 402
Median= 434
Minimum= -2391
Maximum= 1860
Events= 73
1st Quartile= 464
3rd Quartile= 804
IQR= 341
Median= 708
Minimum= -522
Maximum= 1800
Events= 50
2009
2010
2011
2012
2013
Years


ERCOT
Interconnection Loss MW
2700
2400
2100
1800
1500
1200
900
600
300
0
-300
-600
-900
-1200
-1500
-1800
-2100
-2400
1st Quartile= 378
3rd Quartile= 579
IQR= 201
Median= 470
Minimum= -499
Maximum= 1482
Events= 90
1st Quartile= 390
3rd Quartile= 685
IQR= 295
Median= 510
Minimum= -794
Maximum= 1520
Events= 128
1st Quartile= 533
3rd Quartile= 877
IQR= 344
Median= 662
Minimum= -655
Maximum= 2242
Events= 93
1st Quartile= 547
3rd Quartile= 844
IQR= 297
Median= 686
Minimum= -725
Maximum= 2260
Events= 88
1st Quartile= 462
3rd Quartile= 824
IQR= 362
Median= 605
Minimum= -129
Maximum= 1370
Events= 68
2009
2010
2011
2012
2013
Years



No Data Available for 2009 and 2010

Attachment 2

BAL-002-2 R1 Example

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- o Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

Or,

- o Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

In order to illustrate the above requirement the following is provided:

- Responsible Entity Pre-Reporting Contingency Event ACE Value is 100 MW
- Time of the Balancing Contingency Event - 12:05
- Size of the Balancing Contingency Event - 900 MW
- Responsible Entity MSSC - 2,000 MW
- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.

However, if the Responsible Entity experienced another Contingency Event based upon the following:

- Time of the Contingency Event - 12:10
- Size of the Contingency Event - 400 MW
- Responsible Entity Reporting ACE Value at 12:10 – negative 750

The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:10, thus resulting in the required ACE to negative 400 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 400 MW by 12:20.

Now if the Responsible Entity experienced an additional Contingency event prior to 12:20 for example:

- Time of the Contingency Event - 12:15
- Size of the Contingency Event - 200 MW
- Responsible Entity Reporting ACE Value at 12:15 – negative 750

The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:15, thus resulting in the required ACE recovery of to negative 600 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 200 MW by 12:20.

This would continue on for any additional Contingency Events that might occur during the Contingency Event Recovery Period. Note that the adjustments to the Reportable ACE value required for recovery are made only after the subsequent Balancing Contingency Event fully occurs.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-002-2 Background Document

August 2014

RELIABILITY | ACCOUNTABILITY

Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 (Area Control Error (ACE) return to zero within 10 minutes following a disturbance) and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities are required to report all disturbances equal to or greater than 80% of the Balancing Authority's M~~m~~ost S~~s~~evere S~~s~~ingle C~~c~~ontingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate ~~generating~~ capacity and energy be available at all times to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This ~~generating~~ capacity (Contingency Reserve) is necessary to replace ~~generating~~ capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient C~~c~~ontingency R~~r~~eserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and is a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about~~on~~ who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that~~assure~~ the applicable entity is prepared to balance~~s~~ resources and demand and to return~~s~~ its ACE~~Area Control Error~~ to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. The suite of NERC Standard work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, r~~R~~ather~~,~~ it is the combination of the ~~recently passed~~ BAL-001-2 standard, (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively~~are much better at~~ address~~ing~~ issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at I~~i~~nterconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL will allow the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 will require the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may require the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances that could cause transmission overloads if certain units (typically N-1-1 or greater) w~~h~~ere lost and reserves responded.
- ~~In addition, u~~Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and requirements under BAL-002-2 exclude events greater than the MSSC. This provides~~will help ensure reliable operation,~~

clarity of R~~r~~equirements~~, and~~ supports reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there have been 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. When evaluating the data, events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, without regard to the size of a Balancing Authority or RSG and without respect to the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity if they have more stringent standards which require contingency reserve greater than MSSC.

Background

This section discusses the new definitions associated with BAL-002-2.

Balancing Contingency Event

The purpose of BAL-002-2 is to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various manners leaving the ability to measure compliance up to the eye of the beholder. By including the specific definition, it allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary requirements assures FERC's requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition for MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, it is impossible for this event to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing C~~c~~ontingency R~~r~~eserve definition~~s~~ is primarily focused on generation and not Demand Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a r~~R~~equirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and compliment~~ed~~ each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 requires deployment of all Operating R~~r~~eserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event~~, and~~. W~~w~~ithout incurring a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve without violating the NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance for the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 from the existing standard. R5.1 and R5.2 are definitions mixed with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore must add the definition of the Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

~~o~~ Zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); ~~:~~

- ~~o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred~~ however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,~~and~~
- o ~~further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC,~~

o~~, O~~r

~~o~~ Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative): however, ~~:~~

- ~~o less the sum of the magnitudes of all subsequent Balancing Contingency Events that have already occurred~~ during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.~~and~~
- o ~~Further reduced by the magnitude of the difference between (i) the Responsible Entity's Most Severe Single Contingency (MSSC) and (ii) the sum of the magnitudes of the Reportable Balancing Contingency Event and all previous Balancing Contingency Events that have not completed their~~

~~Contingency Reserve Restoration Period when the sum referenced in section (ii) of this bullet is greater than MSSC~~

1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3 Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
  - (ii~~i~~) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within that 105 minute period. ~~when the Responsible Entity experiencing a Reportable Balancing Contingency Event is experiencing an Energy Emergency Alert Level 2 or Level 3.~~
- ~~1.3 Requirement R1 (in its entirety) does not apply when the Responsible Entity experiencing an Balancing Contingency Event exceeding its Most Severe Single Contingency or multiple Balancing Contingency Events whose sum exceeds its Most Severe Single Contingency within a 15 minute period for those events that occur within that 15 minute period. Requirement R1 also shall not apply to subsequent events beyond the 15 minute period but within 105 minutes of the first Balancing Contingency Event if the sum of the events exceeds the Responsible Entity's Most Severe Single Contingency~~.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes a ceiling for the amount of Contingency Reserve and timeframe the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a r~~R~~equirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of C~~c~~ontingency R~~r~~eserve.

Additionally, R1 is designed to assure the applicable entity ~~must~~ uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance. The drafting team has included Attachment 2 illustrating an example of the calculation for Requirement R1.

In addition, the standard drafting team (SDT) through R1 parts 1.2 and R1.3 has clearly identified when R1 is not applicable. By including R1 part 1.2, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. A fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, one could demonstrate events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT~~drafting team~~ elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of the FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity(s) Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team only used the positive events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. The VSL takes these factors into account.

Compliance Calculation

To determine compliance with R1, the ~~required contingency reserve response and~~ measured contingency reserve response is~~are~~ computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive):

- ~~The required contingency reserve response equals the lesser of the megawatt loss of the Reportable Balancing Contingency Event, and, the Most Severe Single Contingency minus the sum of the megawatt losses of any previous Balancing Contingency Events whose start preceded the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period.~~
- The measured contingency reserve response is equal to one of the following:
  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
  - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.
- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - ~~If the required contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 100 percent.~~
  - ~~If the required contingency reserve response is greater than zero,~~

- If~~And~~ the measured contingency reserve response is greater than or equal to the megawatts lost~~required contingency reserve response~~, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
- If~~And~~ the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
- If~~And~~ the measured contingency reserve response is less than the megawatts lost~~required contingency reserve response~~ but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost~~required contingency reserve response~~ – measured contingency reserve response) / megawatts lost~~required contingency reserve response~~)).

The above computations can be expressed mathematically in the following 5~~7~~ sequential steps, labeled as [1-5~~7~~], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

~~REQ_CR_RESP – required contingency reserve response for the Reportable Balancing Contingency Event (MW)~~

~~SUM_PREV - sum of the megawatt losses of any previous Balancing Contingency Events whose start precedes the start of the Reportable Balancing Contingency Event by less than the sum of the Contingency Event Recovery Period and Contingency Reserve Restoration Period (MW)~~

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

~~REQ_CR_RESP = minimum of MW_LOST, and, (MSSC – SUM_PREV) **[1]**~~

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1~~2~~]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2~~3~~]**

~~If REQ_CR_RESP is less than or equal to 0, then COMPLIANCE = 100 [4]~~

If ~~REQ_CR_RESP is greater than 0, and,~~

~~-~~MEAS_CR_RESP is greater than or equal to MW_LOST~~REQ_CR_RESP~~, then

COMPLIANCE = 100 **[3~~5~~]**

If ~~REQ_CR_RESP is greater than 0, and,~~ MEAS_CR_RESP is less than or equal to 0, then

COMPLIANCE = 0 **[4~~6~~]**

If ~~REQ_CR_RESP is greater than 0, and,~~ MEAS_CR_RESP is greater than 0, and,

MEAS_CR_RESP is less than MW_LOST~~REQ_CR_RESP~~, then

COMPLIANCE = 100 * (1 – ((MW_LOST~~REQ_CR_RESP~~ – MEAS_CR_RESP)/ MW_LOST~~REQ_CR_RESP~~)) **[5~~7~~]**

Requirement 2

R2. ~~Except during t~~The Responsible Entity~~'s Contingency Event Recovery Period and the Responsible Entity's Contingency Reserve Restoration Period, or during an Energy Emergency Alert Level 2 or 3 for the Responsible Entity, the Responsible Entity~~ shall maintain ~~an amount of~~ Contingency Reserve, averaged over each Clock Hour, greater than or~~at least~~ equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in:~~.~~

- a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or
- a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or

- an Energy Emergency Alert Level under which Contingency Reserves have been activated.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's~~its~~ Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT~~drafting team~~ believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and does it have sufficient response. Additionally, the drafting team understands that the Responsible Entity's~~ies~~ available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying the operators' hands by removing the use of their available contingency reserve from their toolbox in order to maintain service to load or manage ~~for~~ other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for other issues than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve for only other Contingencies, thus bounding the use of Contingency Reserve to only the N-1 conditions.

Attachment 1

NERC Interconnections 2009-2013

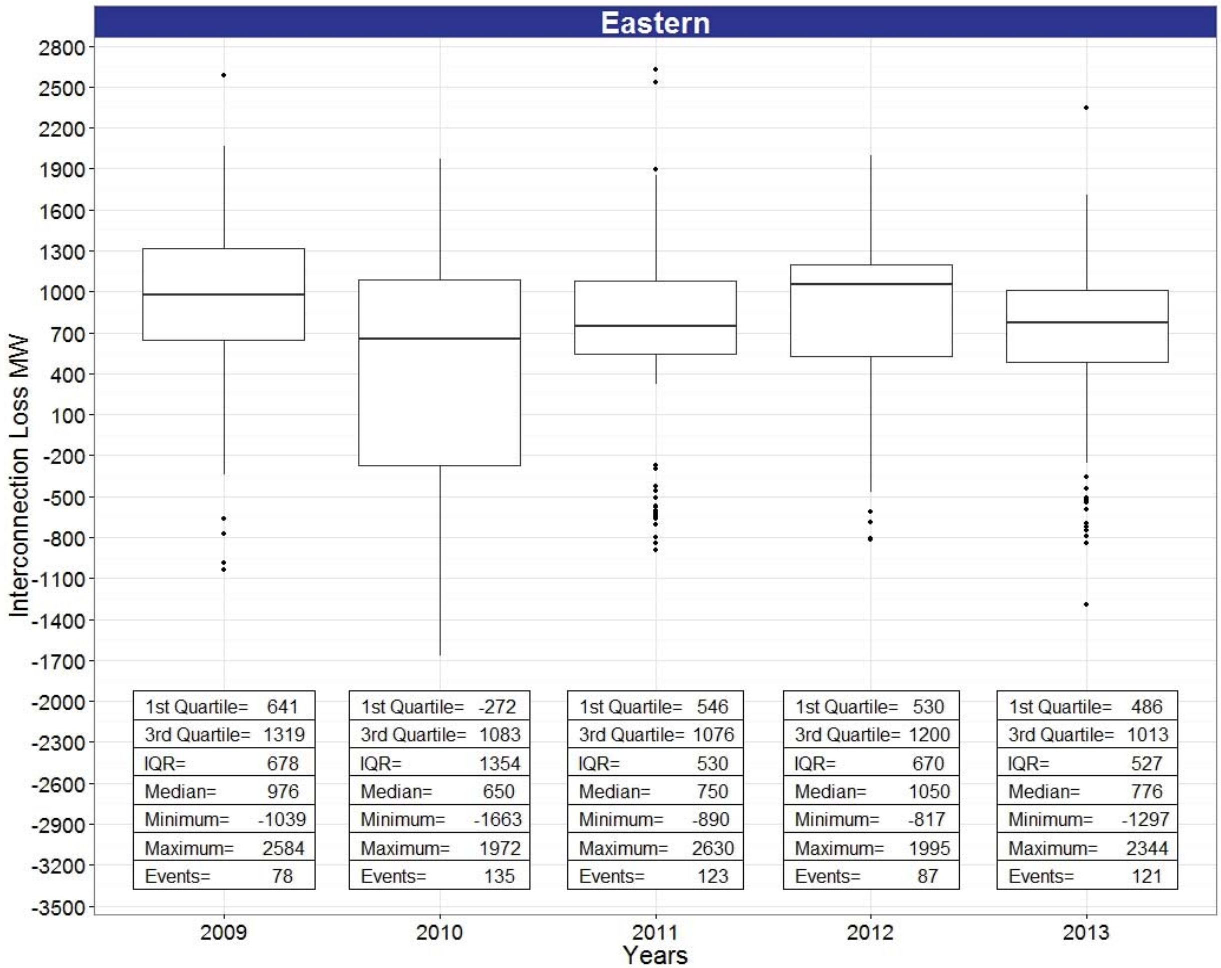
Frequency Events Loss MW Statistics

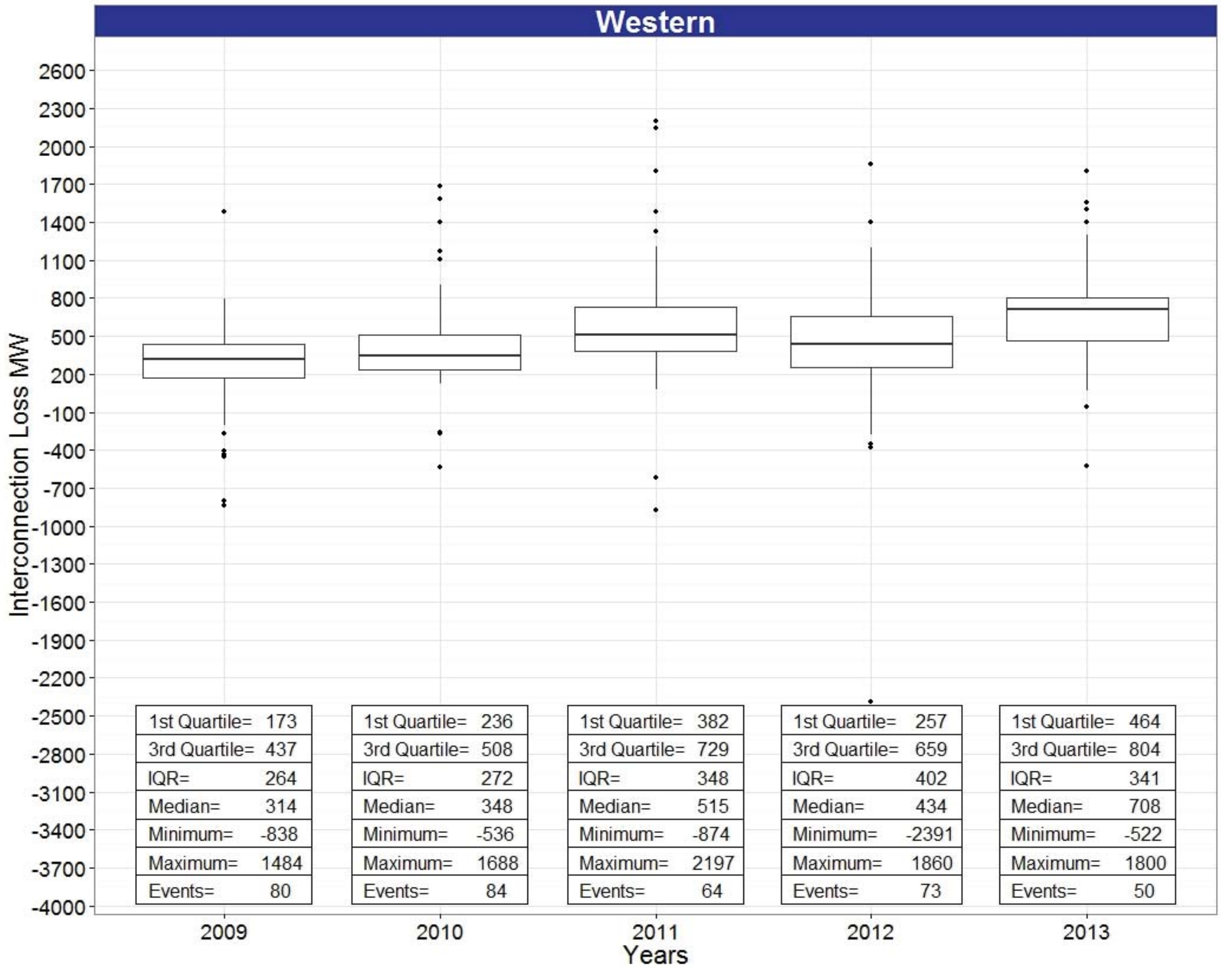
For: NERC BARC Standard Drafting Team

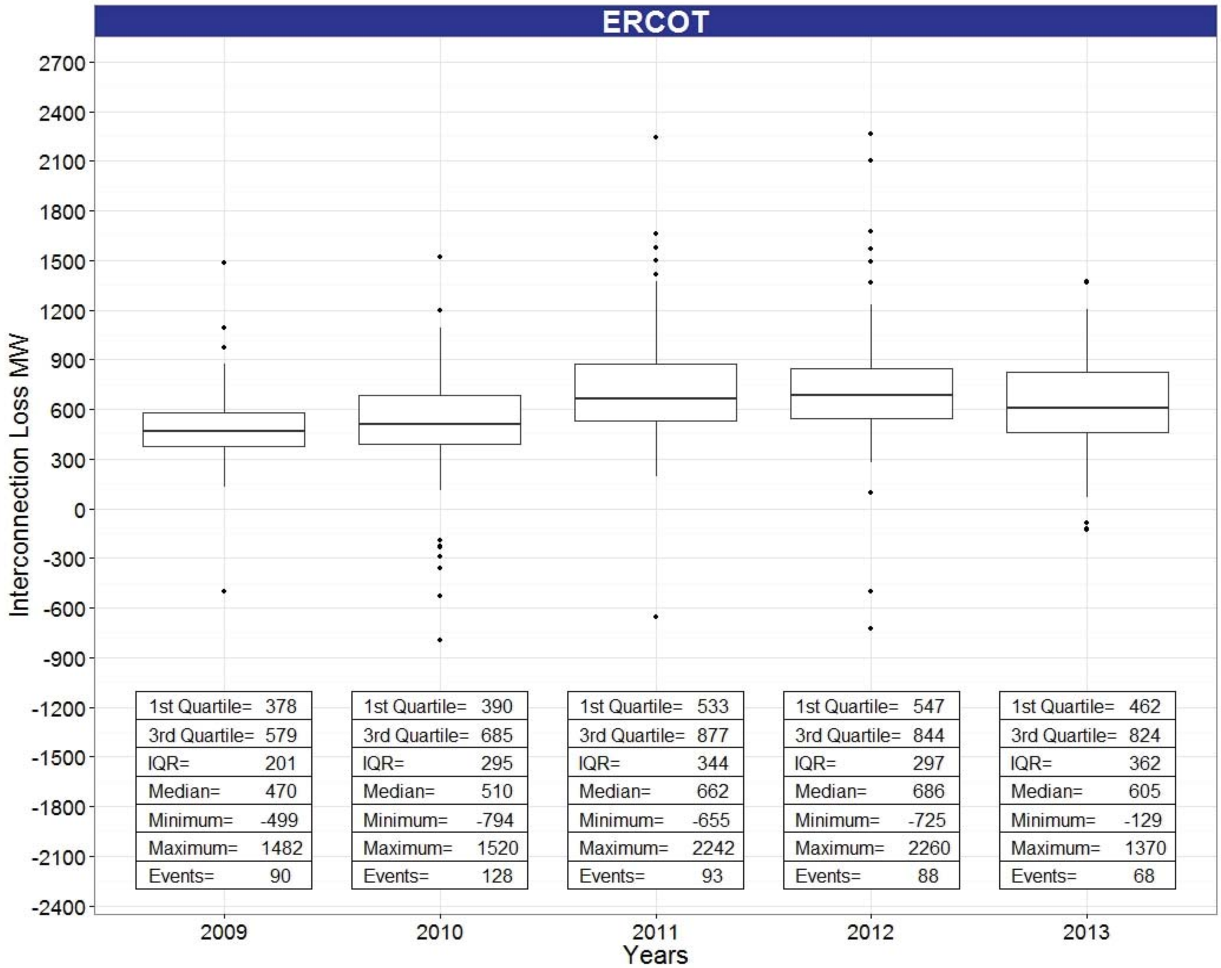
Prepared by: CERTS

Date: October 15, 2013

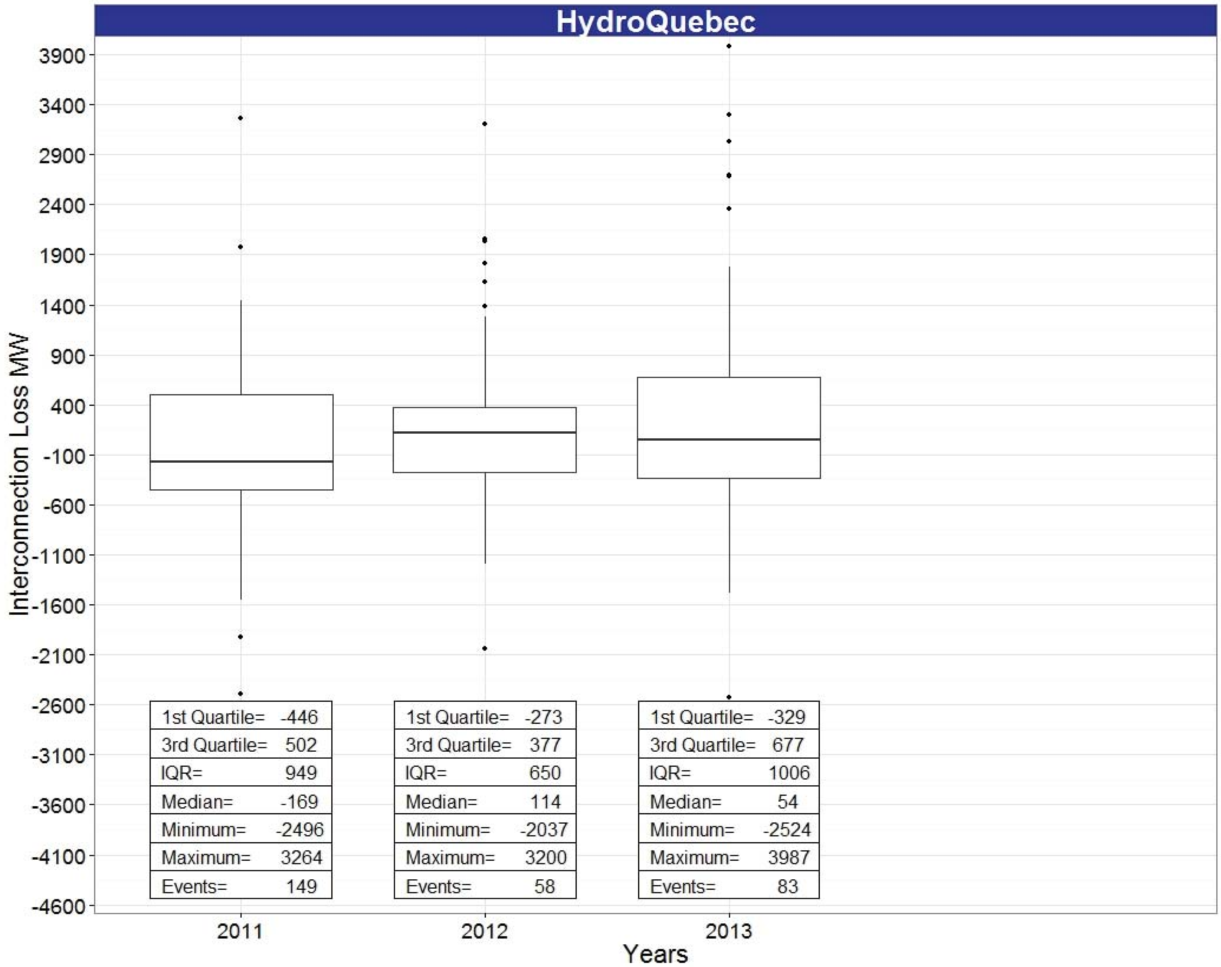
CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS


Eastern
2800
2500
2200
1900
1600
1300
1000
700
400
100
-200
-500
-800
-1100
-1400
-1700
-2000
-2300
-2600
-2900
-3200
-3500
Interconnection Loss MW
1st Quartile= 641
3rd Quartile= 1319
IQR= 678
Median= 976
Minimum= -1039
Maximum= 2584
Events= 78
1st Quartile= -272
3rd Quartile= 1083
IQR= 1354
Median= 650
Minimum= -1663
Maximum= 1972
Events= 135
1st Quartile= 546
3rd Quartile= 1076
IQR= 530
Median= 750
Minimum= -890
Maximum= 2630
Events= 123
1st Quartile= 530
3rd Quartile= 1200
IQR= 670
Median= 1050
Minimum= -817
Maximum= 1995
Events= 87
1st Quartile= 486
3rd Quartile= 1013
IQR= 527
Median= 776
Minimum= -1297
Maximum= 2344
Events= 121
2009
2010
2011
2012
2013
Years


Western
Interconnection Loss MW
Years
2009
2010
2011
2012
2013
1st Quartile= 173
3rd Quartile= 437
IQR= 264
Median= 314
Minimum= -838
Maximum= 1484
Events= 80
1st Quartile= 236
3rd Quartile= 508
IQR= 272
Median= 348
Minimum= -536
Maximum= 1688
Events= 84
1st Quartile= 382
3rd Quartile= 729
IQR= 348
Median= 515
Minimum= -874
Maximum= 2197
Events= 64
1st Quartile= 257
3rd Quartile= 659
IQR= 402
Median= 434
Minimum= -2391
Maximum= 1860
Events= 73
1st Quartile= 464
3rd Quartile= 804
IQR= 341
Median= 708
Minimum= -522
Maximum= 1800
Events= 50



Statistic	2009	2010	2011	2012	2013
1st Quartile=	378	390	533	547	462
3rd Quartile=	579	685	877	844	824
IQR=	201	295	344	297	362
Median=	470	510	662	686	605
Minimum=	-499	-794	-655	-725	-129
Maximum=	1482	1520	2242	2260	1370
Events=	90	128	93	88	68



No Data Available for 2009 and 2010

Attachment 2

BAL-002-2 R1 Example

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

In order to illustrate the above requirement the following is provided:

- Responsible Entity Pre-Reporting Contingency Event ACE Value is 100 MW
- Time of the Balancing Contingency Event - 12:05
- Size of the Balancing Contingency Event - 900 MW
- Responsible Entity MSSC - 2,000 MW
- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.

However, if the Responsible Entity experienced another Contingency Event based upon the following:

- Time of the Contingency Event - 12:10
- Size of the Contingency Event - 400 MW
- Responsible Entity Reporting ACE Value at 12:10 – negative 750

The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:10, thus resulting in the required ACE to negative 400 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 400 MW by 12:20.

Now if the Responsible Entity experienced an additional Contingency event prior to 12:20 for example:

- Time of the Contingency Event - 12:15
- Size of the Contingency Event - 200 MW
- Responsible Entity Reporting ACE Value at 12:15 – negative 750

The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:15, thus resulting in the required ACE recovery of to negative 600 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 200 MW by 12:20.

This would continue on for any additional Contingency Events that might occur during the Contingency Event Recovery Period. Note that the adjustments to the Reportable ACE value required for recovery are made only after the subsequent Balancing Contingency Event fully occurs.

Project 2010-14.1 Mapping Document
Transition of BAL-002-0 to BAL-002-2

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R1	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R2	This requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R3	Requirement R1 and R2	This requirement was broken apart. The requirement was defining two separate actions; 1) to require activation of Contingency Reserves, and 2) to require having Contingency Reserves equal to its MSSC.
BAL-002-0 R4	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R5	This Requirement has been moved into BAL-002-2 Requirement R1 and "Reserve Sharing Group Reporting ACE" definition.	A portion of this requirement was defining how a RSG calculates its ACE. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.
BAL-002-0 R6	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition.	A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Formal Comment Period Now Open through October 2, 2014

Now Available

A 45-day formal comment period for the **BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event** is now open through **8 p.m. Eastern on Thursday, October 2, 2014.**

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 23 – October 2, 2014**.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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

Individual or group. (28 Responses)
Name (13 Responses)
Organization (13 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
Question 1 (28 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
1. Recommend the following change to the definition of a Balancing Contingency Event: Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. A. Sudden loss of generation: a. Due to i. Unit tripping, ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or iii. Sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE. B. Sudden loss of an import, due to forced outage of transmission equipment or the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure that causes an unexpected imbalance between generation and load on the Interconnection. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE. 2. Recommend the following change to the proposed language of Part 1.1: 1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 or an acceptable alternative. 3. Recommend the following change to the proposed language of Part 1.2: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions. The proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so to receive a R1 compliance exemption, making the BA even less able to meet its reserve requirements. 4. Recommend the following changes to the proposed language of R2: R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events or in response to a Reliability Directive. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions. As was stated in the comments for Part 1.2, the proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements. Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that Directive. We believe that the proposed language changes to Requirement 2 satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy". Additional Comments: The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes.

Significant negative consequences of the proposed standard include but are not limited to: 1) The proposed language moves this project from being a performance based standard to a commodity obligation. 2) Increased customer costs absent a demonstrated reliability need as BA's have an incentive to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 3) Increased frequency variation as BA's have an incentive to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 4) Increased SOL and IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate. 5) Reduced Operating Reserves during high demand periods as entities are encouraged to activate reserves during an EEA due to the proposed language in Part 1.2 and R2. 6) As stated above, this standard creates a compliance trap for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2. 7) An increase in BAAL excursion minutes and frequency variation as BA's are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Creates industry confusion regarding the proposed changes to EOP—011 Attachment 1 (at the request of the BARC SDT) by implying that maintaining reserves takes priority over shedding load. 9) Creates an unnecessary administrative burden in tracking the commodity requirements of R2. 10) Provides a disincentive for a BA to assist its neighbor when a formal RSG is not present. 11) As previously noted, we believe that the definition of a BCE needs to include "the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure", else the System Operator may find him/herself in a position of having to choose between activating reserves or shedding load. 12) The Background Document states on page 4 that "BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency" while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. 13) The Background Document states on page 5 that "FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation". Order 693 (at P355) directs the ERO to "define a significant deviation and a reportable event". This misstatement in the Background Document is significant and should be corrected. 14) The Background Document states on page 6 that "the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3". This statement is inconsistent with the current posting. 15) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled "Frequency Events Loss MW Statistics". a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events must be separated.
Group
Florida Power & Light
Mike O'Neil
Florida Power & Light
Section - Definitions of Terms Used in Standard Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection. On B, sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection: There are other mechanisms to handle sudden loss of import and sudden unplanned outage; this should not be in this standard. The IROL standards require operators to take action to prevent reliability issues including re-dispatch and shed load. Having FRSG groups activate Contingency Reserves could have unintended consequences. Examples: In the event that multiple BAs are being affected by the reduction of the import; if all BAs call for reserves the overall recovery will be delayed since the BAs will be importing and exporting power. If TLR is used to curtail import due to reliability issue and the transaction affected was between two or more members of the same FRSG group, the call for reserves will negate the loading relief of the TLR. On C, sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE: This should not be part of BAL-002. Restoration of load should be done in a controlled manner

and if a BA does not have sufficient generation to restore firm load, then the EEA process should be followed.
Group
Arizona Public Service
Janet Smith
Arizona Public Service Company
The additional language added in the applicability section that states: “the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated” is restated within R1.2. AZPS believes that this duplication is unnecessary and that one of the locations should be removed. Additionally, it is not entirely clear what qualifies as use of Contingency Reserve for Contingencies that are not Balancing Authority Contingencies. AZPS would like to request the SDT provide an example or additional clarity to the first bullet in R2 that states, “a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity’s Contingency Reserve falls below its MSSC and must not exceed 90 minutes”.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Madison Gas & Electric
1. We recommend the following change to the definition of a Balancing Contingency Event. Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. A. Sudden loss of generation: a. Due to i. Unit tripping, ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity’s electric system, or iii. Sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity’s ACE; B. Sudden loss of an import, due to forced outage of transmission equipment or the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure that causes an unexpected imbalance between generation and load on the Interconnection. C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity’s ACE. 2. We recommend the following change to the proposed language of R1.1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 or an acceptable alternative. 3. We recommend the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions. R1.2 Comment: The proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements. 4. We recommend the following changes to the proposed language of R2. R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events or in response to a Reliability Directive. This required restoration begins when the Responsible Entity’s Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions. R2 Comment: As stated in the comments for R1.2, the proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to

meet its reserve requirements. Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive. We believe that the proposed language changes to Requirement 2 satisfy the directive in FERC Order 693 to develop “a continent-wide contingency reserve policy”. Additional Comments: The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to: 1) The proposed language moves this project from being a performance based standard to a commodity obligation. 2) Increased customer costs absent a demonstrated reliability need as BA’s are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 3) Increased frequency variation as BA’s are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 4) Increased SOL & IROL exceedance durations as BA’s are reluctant to deploy reserves to mitigate. 5) Reduced Operating Reserves during high demand periods as entities are encouraged to activate reserves during an EEA due to the proposed language in R1.2 & R2. 6) As stated above, this standard creates a compliance trap for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2. 7) An increase in BAAL excursion minutes & frequency variation as BA’s are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Creates industry confusion regarding the proposed changes to EOP—011 Attachment 1 (at the request of the BARC SDT) by implying that maintaining reserves take priority over shedding load. 9) Creates an unnecessary administrative burden in tracking the commodity requirements of R2. 10) Provides a disincentive for a BA to assist its neighbor when a formal RSG is not present. 11) As previously noted, we believe that the definition of a BCE needs to include “the curtailment of Interchange Transaction(s) due to initiation of a TLR procedure”, else the System Operator may find him/herself in a position of having to choose between activating reserves or shedding load. 12) The Background Document states on page 4 that “BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency” while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. 13) The Background Document states on page 5 that “FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation”. Order 693 (at P355) directs the ERO to “define a significant deviation and a reportable event”. This misstatement in the Background Document is significant and should be corrected. 14) The Background Document states on page 6 that “the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3”. This statement is inconsistent with the current posting. 15) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled “Frequency Events Loss MW Statistics”. a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events must be separated.
Individual
Karin Schweitzer
Texas Reliability Entity
Definition of Reportable Balancing Contingency Event: 1) Texas Reliability Entity, Inc. (Texas RE) requests clarification from the SDT as to the meaning and significance of the word “Reportable” in “Reportable Balancing Contingency Event.” As the standard is currently written there is no longer a reporting obligation for balancing contingency events. BAL-002-2 has removed the language that compelled the Responsible Entity to submit the data. The following is the reporting language that has been removed: "Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of

the month following the end of the quarter." Does the SDT consider Measure 1 as the reporting mechanism? Measures are not mandatory nor enforceable components of a Reliability Standard. If the data should be submitted in any other manner than as requested (as evidence for a CMEP activity) by the Compliance Enforcement Authority (CEA) then it will need to be part of a requirement. Texas RE requests clarification from the SDT on the intent. Are Responsible Entities only required to complete the CR Form 1 after a "reportable" event and file it away until the CEA requests it? That appears to be administrative in nature with no reliability benefit. 2) For a single BA interconnection like ERCOT, having the 800 MW value specifically listed in the standard creates inconsistencies over the course of the year. ERCOT loads vary between approximately 25,000 MW and 70,000 MW at different times of the year. For example, a 500 MW unit trip at a load of 30,000 MW may create a frequency excursion below 59.85 Hz, where at a 50,000 MW load it may take a 900 MW unit trip to reach 59.85 Hz. With the current definition, only the 900 MW trip would be a reportable event even though the percentage ACE change and frequency impact are the same. Texas RE suggests that 600 MW is the correct threshold to set as it would call for a greater set of events to be analyzed. A 600 MW threshold more closely aligns to the median of data for the ERCOT region as shown in the chart on page 16 of the BAL-002-2 Background Document. The other regions appear to align close to the median so the ERCOT region number of 800 MW seems to be inconsistent. Requirement R1: The language between the bulleted items in R1, the exceptions in R1.3, and R2 is duplicative and confusing. Texas RE suggests removing the exceptions from the Requirement R1 bullets and only listing them in R1.3 and R2. In addition, the standard could benefit from an Application Guideline section that shows the calculations for different single and multi-generation loss scenarios, possibly in a graphical form. This type of technical information would create consistency across the regions on how R1 is to be interpreted. Requirement R2: Requirement R2 could also benefit from the addition of Application Guideline information showing the calculations for the first two bulleted contingency reserve recovery scenarios. This type of technical information would create consistency across the regions on how R1 is to be interpreted.
Group
Seattle City Light
Paul Haase
Seattle City Light
Seattle City Light appreciates the changes made by the Standard Drafting Team in response to previous comments. The present draft is improved, but Seattle is unable to support the ballot because of remaining concerns, primarily about the definition and use of Most Severe Single Contingency. Specifically, Seattle considers that the definition of Most Severe Single Contingency (MSSC) needs to be changed so that it is not predicated on an event happening to be able to define MSSC. We suggest the following wording to address this problem: "Most Severe Single Contingency (MSSC): The greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG to meet firm system load and export obligation that would occur for any single contingency or credible multiple contingency (excluding export obligation for which Contingency Reserve obligations are designated by E-Tag as being met by the sink Balancing Authority). MSSC will be measured and reported in one minute intervals." In addition, Seattle recommends that Requirement R2 be changed to address the double jeopardy of trying to estimate the average "Clock hour…" If the MSSC definition is changed as above, it makes R2 easier to implement and comply with. We suggest the following new wording for R2: "R2. The Responsible Entity shall maintain Contingency Reserve, greater than or equal to its Most Severe Single Contingency except during periods when the Responsible Entity is in: ..." (rest of text remains as proposed)
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Seminole proposes rewording Part A of the definition of a Balancing Contingency Event to read "Any sudden loss of generation that causes an unexpected change to the responsible entity's ACE." There is no need to list all causes of a "sudden loss of generation," as there are only those related directly to a Unit itself (trip or run back) or loss of a transmission Facility. Additionally, the term Interconnection Facility is not in the Reliability Standards Glossary of Terms, yet it is capitalized. Is it the SDT intent to make the term interconnection facility a new NERC defined term? If so, please

provide the proposed definition of the term. In the definition of MSSC, Seminole proposes the following grammatical changes: • Add a comma after "(RSG)" • Change "member of a RSG" to "member of the RSG" and add a comma after RSG • Add a comma after "at the time of the event" • Change the use of "obligation" to "obligations" R2. Comments: • In the first bullet, what is a "restoration period?" It is not a NERC defined term. The second sentence of the first bullet states it is a "required restoration," and thus it should be its own requirement in the standard. Otherwise, it should be removed from the first bullet. • Also in the first bullet, it is unclear what type of Contingency would result in deployment of an entity's Contingency Reserve and not qualify as a Balancing Contingency Event. Can the SDT provide examples?
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word "shall" instead of "will" to make mandatory the use of the noted CR Form 1. The term "shall" indicates a duty on the subject and is used throughout the NERC Standards in this manner; in this case the responsible entity has a duty to use CR Form 1, so "shall" is the more appropriate term. ReliabilityFirst recommends attaching it to the standards along with the following change for consideration: "The Responsible Entity shall document all Reportable Balancing Contingency Events using Attachment 1 - CR Form 1." 2. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as a reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst recommends completely removing the second paragraph within Measure M2 from the standard. 3. VSL Requirement R1 - There is no VSL associated with an entity failing to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1. ReliabilityFirst recommends the following for an additional Moderate VSL: "The Responsible Entity failed to document Reportable Balancing Contingency Events using CR Form 1 per Requirement R1, Part 1.1"
Individual
Leonard Kula
Independent Electricity System Operator
1. In the last posting, we expressed a concern over disagree with the proposed approach to define new terms that are used solely for this standard, and the term "sudden loss", as follows: a. We disagree with defining new terms and move them to the NERC Glossary when the standard is approved. Many of these terms are used exclusively in this standard only, and as such, should be kept within the standard and not be moved to the NERC Glossary. Moving these terms to the NERC Glossary creates unnecessary maintenance burden, and may create a conflict with similar terms used in other NERC documents. The SDT's response indicates that the defined term is the first step toward addressing the FERC directives. While this may be a preferred approach, not all defined terms need to be incorporated in to the NERC Glossary. We once again urge the SDT to consider keeping the new terms within the standard only and not move them to the NERC Glossary. b. A Balancing Contingency Event is vaguely defined as a "Sudden loss of generation…" or "sudden decline in ACE…". The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where we say that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: "Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein." The SDT's response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. 2. We find the revised R2 to be confusing, and can lend itself to gaming by entities that do not wish to or are unable to comply with the requirement and hence declare EEAs more frequently than necessary. In fact, the amount of OR and the timing to

restore the minimum OR level is material given the requirement to meet CPS1 and DCS (in R1). How and from where, and the amount of reserve a BA needs to have, are driven by meeting the performance targets specified in R1. A BA that fails to maintain the required Contingency Reserve will fail the DCS requirement. Hence, there is no need to create yet another requirement for double jeopardy. We therefore suggest that R2 be removed. Also, R2 with its current wording suggests that there are Contingencies other than BCE that require the activation of Contingency Reserve which we don't agree with as it implies that Bas can no longer activate OR for things other than Contingencies that affect ACE. If R2 is to stay, we suggest changing the word "Contingencies" to have the clause as "events that are not Balancing Contingency Events"
Group
Tennessee Valley Authority
Dennis Chastain
Tennessee Valley Authority
TVA supports the comments being filed by the SERC OC Review Group.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Energy, LLC
The PPL NERC Registered Affiliates support the comments filed by the SERC OC Review Group.
Group
ACES Standards Collaborators
Brian Van Gheem
ACES
(1) We appreciate the SDT with their efforts to address a "continent-wide contingency reserve policy" as stated in FERC Order 693 for NERC standard BAL-002 and issues raised by stakeholders and compliance teams related to other applicable Resource and Demand Balancing Standards. We also appreciate the SDT's attempt to resolve the confusion in the previous draft of this standard with additional Balancing Contingency Events that occur during the Contingency Event Recovery Period of one Balancing Contingency Event. However, we feel that the SDT needs to revise this standard even further. (2) The definition for Balancing Contingency Event is incomplete in Subsection B. The current definition states "Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection," but does not consider import changes due to the initiation of a congestion management or Transmission Loading Relief procedure. We also feel the definition of Balancing Contingency Event focuses solely on the entity experiencing the event and does not accommodate adjacent entities or other members of the entity's Reserve Sharing Group that would be providing emergency assistance. We also believe the SDT should clarify the term Contingency Event Recovery Period by including a reference for when a Responsible Entity uses its Contingency Reserve for Contingencies that are not Balancing Contingency Events. (3) The SDT should reword Part 1.2 of Requirement R1 to account for when a Responsible Entity anticipates an Energy Emergency Alert, not just when the Responsible Entity is experiencing an Energy Emergency Alert. We also believe the SDT should account for the event when a Reliability Coordinator directs the Responsible Entity to deploy a portion of its Contingency Reserves, per IRO-005-3.1a R5. (4) The reference to 105 minutes in Part 1.3 of Requirement R1 appears to be an arbitrary number. We realize that this number is the sum of the Contingency Event Recovery Period and the Contingency Reserve Restoration Period. However, we believe the SDT should include these definitions instead for clarity. (5) We believe the references to "and/or" used to separate the bullets of Requirement R2 will cause confusion and should be removed accordingly. If the drafting team intends for both actions to be complete, then "and" would be appropriate. If one or the other action, or both are intended, the word "or" should be used. This is consistent with other NERC standards and the NERC Rules of Procedure. Regardless, the language needs to be clarified. (6) The reference to 90 minutes in the first bullet of Requirement R2 appears to be an arbitrary number. We realize that this number is the Contingency Reserve Restoration Period and the SDT may have avoided the use of this term since the bullet pertains to deploying Contingency Reserves for Contingencies that are not Balancing Contingency Events. However, we feel that by revising the definition of Contingency Event Recovery Period, as mentioned earlier, the SDT can use the

Contingency Reserve Restoration Period reference in this bullet. (7) We also have concerns that the focus of this standard appears to have shifted to the tracking of Contingency Reserves, and not how an entity uses its Contingency Reserves during an event and how quickly the entity restores these reserves. We believe the former is leading this standard down the path of an administrative burden, while the latter leads to a more performance-based and risk-based approach. (8) Thank you for the opportunity to comment.
Group
IRC Standards Review Committee
Terry Bilke
MISO
1. We have the following questions and concerns with the language in the Applicability subsections for 4.1. Section 4.1.1.1 is problematic in that it states that the RSG is the RE when BA's are in 'active status'. Active status is subjective and likely not a defined term in governing RSG agreements. Additionally, the definition cannot be applied consistently to both R1 and R2. Please consider the following examples where a BA is assumed to be actively maintaining its reserve allocation for the RSG. • A BA experiences a Reportable Event in which it recovers ACE and reserves in accordance with R1 without requesting assistance from the RSG members. The BA is the RE even though it is in 'active status' in the RSG. • For R2 compliance purposes, as long as the BA is actively maintaining its allocation of reserves in accordance with the governing RSG agreement, the RSG is the RE. • Applicability for R2 is further complicated when the BA may participate in an RSG for only part of its footprint and maintains its allocation for the RSG while also maintaining additional reserves for the MSSC in the overall balancing area. In this example, both the BA and the RSG are may be RE's. We believe that to resolve these issues, the BA versus RSG applicability should be moved to the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement. 2. We recommend the following change to the proposed language of R1.1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.] 3. We recommend the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R1.2 Comment: The proposed language is counterintuitive and creates a compliance concern for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements. Further, if a BA declares an EEA, indicating that it is unable to meet reserve requirements, and subsequently deploys some of its reserves to meet increased load does this constitute a deployment of contingency reserves under R1.2 and what evidence does the BA provide to demonstrate compliance? 4. We recommend the following changes to the proposed language of R2. R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events [or in response to a Reliability Directive.] This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R2 Comment: As stated in the comments for R1.2, the proposed language is counterintuitive and creates a compliance concern for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements. Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability

impact on the BES, but be non-compliant under R2 for following that directive. We believe that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop “a continent-wide contingency reserve policy”, as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. If, however, the SDT decides that it is necessary to keep the commodity obligations currently proposed in R2, we believe that the suggested R2 changes above will reduce unintended adverse reliability consequences while further reinforcing satisfaction of the directive. Additional Comments: The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to: 1) The proposed language moves this project from being a performance based standard to a commodity obligation. 2) Creates a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: a. R2 requires dated documentation that demonstrates that hourly Contingency Reserves were at least equal to hourly MSSC. In a three year audit period that is 26,280 one hour intervals! b. Both R1 & R2 require dated documentation for all Reportable Balancing Contingency Events that occur when an EEA and Contingency Reserves have been activated. When an RE declares an EEA2 or EEA3, under the current TOP standard, they are declaring that they may be unable to meet required reserve requirements. When the load increases after the EEA has been declared and units that were previously providing CR are then dispatched higher to balance the increased load, does that constitute deploying CR? What evidence does the RE provide? 3) Increased customer costs absent a demonstrated reliability need as BA’s are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 4) Increased frequency variation as BA’s are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 5) Increased SOL & IROL exceedance durations as BA’s are reluctant to deploy reserves to mitigate. 6) As stated above, this standard creates a compliance concern for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2. 7) An increase in BAAL excursion minutes & frequency variation as BA’s are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Provides a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect. 9) The Severe VSL omits the “from a Reportable Balancing Contingency Event” language that is included in the Lower, Moderate, & High VSLs. We believe this omission was an oversight. 10) The Background Document states on page 4 that “BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency” while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. 11) The Background Document states on page 5 that “FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation”. Order 693 (at P355) directs the ERO to “define a significant deviation and a reportable event”. This misstatement in the Background Document is significant and should be corrected. 12) The Background Document states on page 6 that “the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3”. This statement is inconsistent with the current posting. 13) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled “Frequency Events Loss MW Statistics”. a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events should be separated. 14) Finally, the ISOs do not see a need to change from the current approach of using 80% of the largest unit within the RSG or BA or a smaller amount as chosen by the responsible entity.
Individual
Dan Roethemeyer
Dynegy
1. Dynegy's Electric Energy Inc. (EEI) entity is concerned that “Coordinated adjustments to Interchange Schedules” has been removed from allowed list of Contingency Reserve in the proposed

standard. EEI does not have load within its balancing area and relies on adjusting interchange schedules in order to meet its DCS obligation. It is not clear in the draft standard that adjustments to interchange schedules will be allowed in order to meet this obligation. EEI suggests continuing to allow “Coordinated adjustments to Interchange Schedules” as an option to meet DCS obligations in the standard.
Individual
Marie Knox
MISO
We agree with the comments submitted by the IRC’s Standards Review Committee. Additionally, we respectfully offer the following comments. One key concern is the inequitable definition of reportable events. The Eastern Interconnection is asked to report on units that are a fraction of the size of the other Interconnections. Here is the comparison. 14% East 25% West 114% ERCOT 108% HQ The East will be reporting performance for proportionally many more events than the other Interconnections, perhaps nearly 10 times as many. The threshold in the East should be 1000 MW or 80% of the largest unit within the BA or RSG, whichever is lesser. While well-intentioned, over-enforcement of the current BAL-002 standard has led to operators shedding load for no reliability reason just to achieve a zero ACE. The IROL standards are the backstop on reliability on whether ACE is causing a problem. The changes proposed in this standard will now have operators shedding load for cases where its reserves drop below a particular number. There is no doubt this tendency to over-enforce BAL-002 will continue. Each BA needs a different amount and type of reserve based on many factors. The true demonstration of reserve adequacy is CPS1, BAAL, DCS and IROL performance. It’s unfortunate that NERC is moving away from a performance based approach to standards toward a zero-defect commodity obligation. The current DCS is well understood and performance has been stellar. We would be happy to provide data to show this is the case. The proposed standard makes many changes to existing process without a demonstrated reliability need. Additionally, many of the changes do not appear to be within the scope of the SAR nor an Order No. 693 directive. This sets an unfortunate precedent. We believe the present standard should be kept mostly intact. We agree with adding clarity that the objective of the standard is to respond to events up to the Most Severe Single Contingency and that the BA should implement emergency actions if necessary to respond to events > MSSC. This does not mean shedding load as long as the BA is not causing an exceedance of an IROL. One particular challenge is the lack of common definitions for reserves. The team is proposing a commodity requirement without a definition of how to quantify the hourly number. We believe that reliability would be better served if the team followed the Order No. 693 directive to create uniform definitions in a policy document. Once these terms are defined and commented on by the Industry in the document, NERC should add the types of reserves to “Attachment 1-TOP-005 Electric System Reliability Data”, with the expectation in the policy that Reliability Coordinators collect this information in real time for use in the EEA process. We believe there would be significant reliability value in giving RCs continent-wide visibility of the current state of Contingency Reserves (something callable in 10 minutes, fully deployed in 15 minutes and sustainable for at least 90 minutes) and Replacement Reserves (e.g. something callable in 90 minutes and sustainable for say 4 hours). This would directly contribute to reliability by providing objective information to BAs and RCs in managing Energy Emergency Alerts.
Group
Duke Energy
Michael Lowman
Duke Energy
(1) Duke Energy suggests the following revision to R1.2: “1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load.” We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R1 during those instances where Contingency Reserves are utilized to serve load. (2) Duke Energy suggests the following revision to R2 bullet 3: “• an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load.” We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R2 during those instances where Contingency Reserves are utilized to serve load. (3) Duke Energy suggests the following revision to item A.a.ii. of the Balancing Contingency Event definition: “ii. Loss of generator Facility resulting in isolation of the generator from the Bulk Electric

System or from the responsible entity’s electric system, or…” We believe the use the word “Interconnection” could be viewed as redundant based on it being implied within the NERC definition of “Facility”. (4) Duke Energy seeks clarification on item B of the Balancing Contingency Event (BCE) definition. A BCE should be predicated on a deviation in Area Control Error (ACE) . As written, we are unclear why item B is even part of the definition because we believe Item B is redundant with item A.a.ii.
Individual
Spencer Tacke
Modesto Irrigation District
I am voting NO because I cannot support a change from 15 minutes to 105 minutes in Section R1 1.3. I could , however, support a change from 15 minutes to 30 minutes. Thank you.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
We believe that this draft certainly is an improvement from the last draft and from the actual standard. We suggest the SDT to take into account additional minor adjustments to improve the actual draft. We propose that the standard should follow the new NERC standard format by placing measures with associated requirements. The proposed definition for "Balancing Contingency Event", the term "Interconnection Facility" should not be capitalized as it is not a defined term in the NERC Glossary. Only the term "Facility" should be capitalized. "Interconnection" is a defined term but refers to one of the major electric system (Eastern, ERCOT, etc.) when capitalized. In this case, the term "interconnection Facility" seems to refer to a facility that is used to interconnect generation to the system. In the proposed definition for "Most Severe Single Contingency", the term "sink" should be capitalized as "Sink Balancing Authority" is a defined term in the NERC Glossary. Also, some single contingencies may lead to a generation loss as well as a load loss due to bus configuration. This load could either be end-user load or DC converters. We suggest that the “Reportable Balancing Contingency Event” and “Most Severe Single Contingency” definitions explicitly take the load loss into account. We suggest adding the words “… resulting in the net loss of MW output reduced by any concurrent load loss” in both definitions. We noticed that the background document discusses the issue stated above in the MSSC section but may not be exact in all cases. For example, a BA has three 600 MW units in a substation and a 200 MW transformer that serves load. Due to unavailable equipment in the substation, there is a bus fault that can lead to the loss of two units (1200 MW) and the transformer (200 MW). In this case, we believe that the entity’s MSSC should be 1000 MW. This following sentence is not true in all cases: “Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, it is impossible for this event to be the entity’s MSSC » . We suggest removing it from standard. R1: We suggest that the part that addresses Balancing Contingency Event (BCE) occurrences during the Contingency Event Recovery Period be not duplicated. Moreover, we ask further explanation about the use of the expression "beginning at the time of". Also, we believe that part unnecessary. The reduction cannot be applied before a BCE actually happens and the reduction is applied to the required recovery value that must be reached by the end of the recovery period. Thus, the time of the application of the reduction is not relevant. As long as the event fully occurs within the recovery period the adjustment can be made. The expression "beginning at the time of" is also not consistent with the last sentence of the background document: "Note that the adjustments to the Reportable ACE value required for recovery are made only after the subsequent Balancing Contingency Event fully occurs." Whereas the requirement states "…beginning at the time of each individual Balancing Contingency Event". To address those issues to be more clear and concise, we suggest rewording the two bullets as follows: "Zero, if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero Or Its Pre-Reporting Contingency Event ACE Value, if that value was negative. In both cases, the required recovery value for the Reporting ACE shall be reduced by the magnitude of each subsequent Balancing Contingency Event that fully occurs during the Contingency Event Recovery Period." Section 1.2 should be included in 1.3 as it is also a condition under which R1 does not apply (1.3 would become 1.2). Also in 1.3, the first part addressing BCE > MSSC is redundant since R1 applies to Reportable BCE which is defined as a BCE <= MSSC. We suggest removing the first part of 1.3 (i) and only keep the second part (ii). We propose: "1.2 Requirement R1 (in its entirety) does not apply: • when the Responsible Entity is experiencing an

Energy Emergency Alert Level under which Contingency Reserves have been activated, or • after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105 minute period." The graphs in Attachment 1 of the background document should exclude load events in the statistics. These events are not relevant for the BAL-002 standard. Additionally, it makes it difficult to understand how the MW threshold for the Interconnections established from these graphs. The SDT should explain the data shown in the graphs and how it relates to the Interconnection minimums. Additionally, "hydroquebec" graph should be renamed "Quebec" Interconnection. In Attachment 2 of the background document there seem to be a mistake in the example. The second Balancing Contingency Event (200MW at 12:15) that occurs during the recovery period is cumulative to the first one resulting in a required ACE recovery value of negative 600 MW. However, the next sentence states that the responsible entity would return its Reporting ACE to negative 200 MW by 12:20 which would be a more severe requirement in response to a subsequent BCE during a recovery period. It must be corrected in the background document.
Individual
Catherine Wesley
PJM Interconnection
1. We have the following questions and concerns with the language in the Applicability subsections for 4.1. Section 4.1.1.1 is problematic in that it states that the RSG is the RE when BA's are in 'active status'. Active status is subjective and likely not a defined term in governing RSG agreements. Additionally, the definition cannot be applied consistently to both R1 and R2. Please consider the following examples where a BA is assumed to be actively maintaining its reserve allocation for the RSG. • A BA experiences a Reportable Event in which it recovers ACE and reserves in accordance with R1 without requesting assistance from the RSG members. The BA is the RE even though it is in 'active status' in the RSG. • For R2 compliance purposes, as long as the BA is actively maintaining its allocation of reserves in accordance with the governing RSG agreement, the RSG is the RE. • Applicability for R2 is further complicated when the BA may participate in an RSG for only part of its footprint and maintains its allocation for the RSG while also maintaining additional reserves for the MSSC in the overall balancing area. In this example, both the BA and the RSG are may be RE's. We believe that to resolve these issues, the BA versus RSG applicability should be moved to the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement. 2. We recommend the following change to the proposed language of R1.1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.] 3. We recommend the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R1.2 Comment: The proposed language is counterintuitive and creates a compliance concern for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements. Further, if a BA declares an EEA, indicating that it is unable to meet reserve requirements, and subsequently deploys some of its reserves to meet increased load does this constitute a deployment of contingency reserves under R1.2 and what evidence does the BA provide to demonstrate compliance? 4. We recommend the following changes to the proposed language of R2. R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events [or in response to a Reliability Directive.] This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R2 Comment: As stated in the

comments for R1.2, the proposed language is counterintuitive and creates a compliance concernfor the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements. Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive. We believe that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop “a continent-wide contingency reserve policy”, as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. If, however, the SDT decides that it is necessary to keep the commodity obligations currently proposed in R2, we believe that the suggested R2 changes above will reduce unintended adverse reliability consequences while further reinforcing satisfaction of the directive. Additional Comments: The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to: 1) The proposed language moves this project from being a performance based standard to a commodity obligation. 2) Creates a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: a. R2 requires dated documentation that demonstrates that hourly Contingency Reserves were at least equal to hourly MSSC. In a three year audit period that is 26,280 one hour intervals! b. Both R1 & R2 require dated documentation for all Reportable Balancing Contingency Events that occur when an EEA and Contingency Reserves have been activated. When an RE declares an EEA2 or EEA3, under the current TOP standard, they are declaring that they may be unable to meet required reserve requirements. When the load increases after the EEA has been declared and units that were previously providing CR are then dispatched higher to balance the increased load, does that constitute deploying CR? What evidence does the RE provide? 3) Increased customer costs absent a demonstrated reliability need as BA’s are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 4) Increased frequency variation as BA’s are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 5) Increased SOL & IROL exceedance durations as BA’s are reluctant to deploy reserves to mitigate. 6) As stated above, this standard creates a compliance concernfor System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2. 7) An increase in BAAL excursion minutes & frequency variation as BA’s are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Provides a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect. 9) The Severe VSL omits the “from a Reportable Balancing Contingency Event” language that is included in the Lower, Moderate, & High VSLs. We believe this omission was an oversight. 10) The Background Document states on page 4 that “BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency” while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. 11) The Background Document states on page 5 that “FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation”. Order 693 (at P355) directs the ERO to “define a significant deviation and a reportable event”. This misstatement in the Background Document is significant and should be corrected. 12) The Background Document states on page 6 that “the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3”. This statement is inconsistent with the current posting. 13) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled “Frequency Events Loss MW Statistics”. a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events should be separated.
Individual

Cheryl Moseley
Electric Reliability Counccil of Texas, Inc.
ERCOT generally supports the comments submitted by the ISO/RTO Council's Standards Review Committee (IRC SRC) and provides the following additional comments: 1. ERCOT respectfully submits the following comments to remove ambiguity and streamline the definitions proposed to support this draft of the BAL-002-2 standard: a. The use of the term sudden is ambiguous and could create confusion. The following revisions are proposed: Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute. A. Unexpected loss of generation: a. Due to i. Unit tripping ii. Loss of generator Interconnection Facility resulting in isolation of the generator from the Bulk Electric System iii. Unexpected, unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Unexpected loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and load within the Balancing Authority Area. C. Unexpected restoration of a load utilized as a supply resource to balance load and supply in the Balancing Authority Area that causes an unexpected change to the responsible entity's ACE. b. The definition of Most Severe Single Contingency should be streamlined to ensure that it is clear and unambiguous. The use of phrases such as "at the time of the event" could create confusion and should be eliminated from the definition. The following revisions are proposed: Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the responsible entity to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority). c. The definition of Reportable Balancing Contingency Event should be streamlined to ensure that it is clear and unambiguous. The use of phrases such as "at the time of the event" could create confusion and should be eliminated from the definition. The following revisions are proposed: Reportable Balancing Contingency Event: Any Balancing Contingency Event causing a loss of MW output less than or equal to 80% of the Most Severe Single Contingency or the amount listed below for the applicable Interconnection and occurring within a one-minute interval of the initial decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the Responsible Entity upon written notification to the Regional Entity. • Eastern Interconnection - 900 MW • The Western Interconnection – 500 MW • ERCOT – 1000 MW • Quebec – 500 MW d. The definition of Contingency Event Recovery Period should be streamlined to ensure that it is consistent with other definitions and concepts within the proposed standards and is clear and unambiguous. The following revisions are proposed: Contingency Event Recovery Period: A period beginning at the conclusion of a Reportable Balancing Contingency Event and extends for fifteen minutes thereafter. e. The definition of Contingency Reserve Restoration Period should be streamlined to ensure that it is clear and unambiguous. The following revisions are proposed: Contingency Reserve Restoration Period: A period of 90 minutes following the end of the Contingency Event Recovery Period. f. The definition of Contingency Reserve should be streamlined to ensure that it is clear and unambiguous. The following revisions are proposed: Contingency Reserve: Capacity that may be deployed by the Responsible Entity to balance load and supply within its Balancing Authority Area. The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation. 2. ERCOT has the following questions and concerns with the language in the Applicability subsections for 4.1. a. ERCOT respectfully submits that the Applicability Section is not the appropriate section within a standard to establish clarifications or compliance exceptions. This could create confusion as to when the standard is applicable to particular entities. ERCOT would prefer that all references to possible compliance exceptions are additional criteria that are addressed in Requirements and should be removed from the Applicability Section. To ensure that these additional criteria are retained within the standard, the requirements themselves should be reviewed and BA versus RSG applicability should be addressed within the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement. In the alternative, to ensure clarity, the following revisions are proposed: 4. Applicability: Applicability is determined on an individual Reportable Balancing Contingency Event basis. 4.1. Responsible Entity 4.1.1 Balancing Authority that is not an Energy Emergency Alert Level under which Contingency Reserves have been activated. 4.1.2 Reserve Sharing Group that is (1) active within a particular Balancing Authority Area under the applicable agreement or governing rules for the Reserve Sharing Group and (2) not an

Energy Emergency Alert Level under which Contingency Reserves have been activated. 3. ERCOT respectfully submits that the Requirement R1 is unnecessarily complex and could be streamlined to present more definitive requirements and criteria. To ensure clarity, the following revisions are proposed: R1. The responsible entity experiencing a Reportable Balancing Contingency Event shall return to its pre-Reporting Contingency Event Reporting ACE within the Contingency Event Recovery Period. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations] • If the responsible entity's Pre-Reporting Contingency Event Reporting ACE Value was positive or equal to zero, recovery shall be demonstrated by returning its Reporting ACE to zero. • If the responsible entity's Pre-Reporting Contingency Event Reporting ACE Value was negative, recovery shall be demonstrated by returning its Reporting ACE to the value utilized for Reporting ACE immediately preceding the start of the Reportable Contingency Event. o When subsequent Balancing Contingency Events occur during the Contingency Event Recovery Period, the Reporting ACE value to be recovered shall be reduced at the start of and by the magnitude of each subsequent Balancing Contingency Event that occurs during the Contingency Event Recovery Period. Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 4. Requirement R1.1 is administrative in nature and should be removed from the Standard and included in the ROP or a guidance document. As an alternative to removing the requirement, ERCOT recommends the following change to the proposed language of R1.1 to provide an alternative to using CR Form 1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.] Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 5. ERCOT suggested above that compliance exceptions be more appropriately documented in the requirements. Further, the proposed language creates a potential adverse reliability consequence and operational concern for the System Operator because a Balancing Authority may declare an EEA3 (under the revised language of yet to be approved EOP-011) to indicate that it is unable to meet reserve requirements, but deployment of reserves may not yet be necessary. However, to receive an R1 compliance exemption, the BA would need to deploy some of those reserves - even if there is no immediate need to do so. This requirement would result in the impacted BA being even less able to meet its reserve requirements. Further, where subsequent reserve deployments occur to meet increased load, it is unclear as to whether this would constitute a deployment of contingency reserves under R1.2. If so, what evidence does the BA provide to demonstrate compliance? To resolve these issues as well as those discussed under Requirement R1.3, ERCOT recommends the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: (i) It is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated. (ii) It has declared that it may be unable to meet reserve requirements due to system conditions (iii) It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. (iv) The combined magnitude of multiple Balancing Contingency Events occurring within a 15 minute period exceeds the Responsible Entity's Most Severe Single Contingency. Corresponding revisions are suggested to the VSLs, Measures, and Associated Compliance Information as necessary to ensure consistency. 6. ERCOT suggests the deletion of Requirement R1.3 and the consolidation of all exceptions from compliance into one Requirement for ease of review and comprehension. Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. 7. ERCOT respectfully submits that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy", as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. Accordingly, the SDT recommends the deletion of Requirement R2. Additionally, ERCOT reiterates its operational and reliability concerns set forth in Comment 6 above and notes that Requirement R2 should acknowledge the potential impacts of responding to a Reliability Directive. Specifically, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive. Accordingly, as an alternative to deletion of Requirement R2, ERCOT suggests the following changes to the proposed language of Requirement R2 to reduce ambiguity and the potential for unintended adverse reliability consequences and satisfy the aforementioned directive: R2. The Responsible Entity shall maintain Contingency Reserves greater than or equal to its Most Severe Single Contingency. Such reserves shall be measured using the average Contingency Reserve amount over each clock hour except when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • For the restoration

period following Contingency Reserve deployment in response to a Contingencies that are not Balancing Contingency Events or a Reliability Directive, which restoration period shall not exceed 90 minutes and begins when the Responsible Entity's Contingency Reserve falls below its MSSC; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] Corresponding revisions are suggested to the VSLs and Measures as necessary to ensure consistency. Additional Comments: 1. ERCOT respectfully notes that a reliability or performance-related need, such as negative historical trends for DCS recovery or compliance, has not been noted and, therefore, the proposed changes may not be necessary to ensure the reliability of the Bulk Electric System. ERCOT supports the clarification and improvement of Reliability Standards generally. In this circumstance, significant negative consequences of the proposed standard have been identified. These include, but are not limited to: a. The transformation of Contingency Reserve requirements from a reliability standard to a commodity obligation. b. Increased customer costs despite the absence of a demonstrated reliability need as BAs will be incentivized to purchase contingency reserves beyond that needed to recover from the loss of MSSC. c. Operational modifications and concerns such as: i. Increased frequency variation as BAs will be incentivized to change generation dispatch at the top of each hour to meet the R2 commodity obligation. ii. Increased SOL & IROL exceedance durations as BAs will be reluctant to deploy reserves to mitigate impacts. iii. Increased BAAL excursion minutes as BAs are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. d. Provision of a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect. e. Creation of a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: i. R2 requires dated documentation that demonstrates that hourly Contingency Reserves that were at least equal to the MSSC. In a three year audit period that is 26,280 one hour intervals. 1. ERCOT respectfully notes the following potential inconsistencies and omissions in the BAL-002 Standard and associated documentation: a. The Severe VSL omits the "from a Reportable Balancing Contingency Event" language that is included in the Lower, Moderate, & High VSLs. b. The Background Document states on page 4 that "BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency" while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. c. The Background Document states on page 5 that "FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation". However, Order 693 (at P355) directs the ERO to "define a significant deviation and a reportable event". This should be corrected. d. The Background Document states on page 6 that "the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3". This statement is inconsistent with the current posting and should be corrected. e. The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled "Frequency Events Loss MW Statistics". i. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. ii. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation, then loss of generation and loss of load events should be separated.
Group
SERC OC Review Group
Steve Corbin
SERC RRO
1. We have the following questions and concerns with the language in the Applicability subsections for 4.1. Section 4.1.1.1 is problematic in that it states that the RSG is the RE when BA's are in 'active status'. Active status is subjective and likely not a defined term in governing RSG agreements. Additionally, the definition cannot be applied consistently to both R1 and R2. Please consider the following examples where a BA is assumed to be actively maintaining its reserve allocation for the RSG. • A BA experiences a Reportable Event in which it recovers ACE and reserves in accordance with R1 without requesting assistance from the RSG members. The BA is the RE even

though it is in ‘active status’ in the RSG. • For R2 compliance purposes, as long as the BA is actively maintaining its allocation of reserves in accordance with the governing RSG agreement, the RSG is the RE. • Applicability for R2 is further complicated when the BA may participate in an RSG for only part of its footprint and maintains its allocation for the RSG while also maintaining additional reserves for the MSSC in the overall balancing area. In this example, both the BA and the RSG are may be RE’s. We believe that to resolve these issues, the BA versus RSG applicability should be moved to the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement. R1 – clarity needs to be added to phase “(i) beginning at the time of” to explain how this phrase applies. 2. We recommend the following change to the proposed language of R1.1. R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.] 3. We recommend the following change to the proposed language of R1.2. R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R1.2 Comment: The proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements. Further, if a BA declares an EEA, indicating that it is unable to meet reserve requirements, and subsequently deploys some of its reserves to meet increased load does this constitute a deployment of contingency reserves under R1.2 and what evidence does the BA provide to demonstrate compliance? 4. We recommend the following changes to the proposed language of R2. R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity’s Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or • response to a Reliability Directive; and/or • a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or • an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.] R2 Comment: As stated in the comments for R1.2, the proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements. Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive. We believe that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop “a continent-wide contingency reserve policy”, as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. If, however, the SDT decides that it is necessary to keep the commodity obligations currently proposed in R2, we believe that the suggested R2 changes above will reduce unintended adverse reliability consequences while further reinforcing satisfaction of the directive. Additional Comments: The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to: 1) The proposed language moves this project from being a performance based standard to a commodity obligation. 2) Creates a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: a. R2 requires dated documentation that demonstrates that hourly Contingency Reserves were at least equal to hourly MSSC. In a three year audit period that is 26,280 one hour intervals! b. Both R1 & R2 require dated documentation for all Reportable Balancing Contingency Events that occur when an EEA and Contingency Reserves have been activated. When

an RE declares an EEA2 or EEA3, under the current TOP standard, they are declaring that they may be unable to meet required reserve requirements. When the load increases after the EEA has been declared and units that were previously providing CR are then dispatched higher to balance the increased load, does that constitute deploying CR? What evidence does the RE provide? 3) Increased customer costs absent a demonstrated reliability need as BA's are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC. 4) Increased frequency variation as BA's are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation. 5) Increased SOL & IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate. 6) As stated above, this standard creates a compliance trap for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2. 7) An increase in BAAL excursion minutes & frequency variation as BA's are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Provides a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect. 9) The Severe VSL omits the "from a Reportable Balancing Contingency Event" language that is included in the Lower, Moderate, & High VSLs. We believe this omission was an oversight. 10) The Background Document states on page 4 that "BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency" while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves. 11) The Background Document states on page 5 that "FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation". Order 693 (at P355) directs the ERO to "define a significant deviation and a reportable event". This misstatement in the Background Document is significant and should be corrected. 12) The Background Document states on page 6 that "the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3". This statement is inconsistent with the current posting. 13) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled "Frequency Events Loss MW Statistics". a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events should be separated. c. Last step in example on Page 22 of the redline version, the -200 MW appears to be incorrect. The required ACE Recovery should be -600 MW. The comments expressed herein represent a consensus of the views of the above-named members of the SERC OC Review Group only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
NA
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Associated Electric Cooperative, Inc. - NCR01177
AECI agrees with SERC comments 2, 3, and 4. The SDT has used the term "sudden loss" and "sudden decline" in the definitions for Balancing Contingency Event and Reportable Balancing Contingency Event. Would the SDT provide some additional guidance on what specially would be considered "sudden"? Should this be determined from a percentage of the unit lost over a time period? Would the SDT be able to provide an example of what is considered sudden and what is not (in addition to including language in the standard that aligns with this example)? AECI agrees with SERC that the use of "active status" within 4.1.1.1 is ambiguous and AECI suggests the SDT include more direction on what active status entails. However, inclusion of this concept within the requirements (as opposed to the applicability) may create more confusion than simply including more direction on what active status actually is. Serious consideration should made for whatever language to avoid the unintentional consequence of a BA in an RSG being required to cover their full

MSSC reserves when not in “active status” of the RSG. To this end, it may be advantageous to apply the exception to the RSG, and not the BA. Proposed 4.1.1.1: A Balancing Authority is the Responsible Entity when contractual membership to a Reserve Sharing Group does not exist. Proposed 4.1.1.2: A Reserve Sharing Group is the Responsible Entity for all Balancing Authority members under contract of that Reserve Sharing Group. AECI suggests the Contingency Event Recovery Period should be 30 minutes to align with other standards (BAAL).
Individual
Jo-Anne Ross
Manitoba Hydro
1) R 1.2 states: A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated. R 1.3 states: Requirement R1 (in its entirety) does not apply: • (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or • (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity’s Most Severe Single Contingency for those events that occur within a 105 minute period. R 1.2 could be added as a bullet point in R 1.3 unless there is something that distinguishes 1.2 from 1.3. If so, this should be made clear. 2) M2 states: "If any portion of the Clock Hour is excluded by rule (restoration period following a Contingency which is not a Balancing Contingency Event, an Energy Emergency Alert Level user which Contingency Reserves have been activated, Contingency Reserve Recovery Period overlap or Contingency Reserve Restoration Period overlap) then that Clock Hour is excluded from evaluation." The terminology “excluded by rule” is currently unclear and could be clarified by referring to time periods that are excluded in R2. 3) D 1.1 states: 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. This does not take Canadian legislation into account as the term “Compliance Enforcement Authority” can have different meanings in jurisdictions outside of the United States. An additional sentence could be added stating that “ In jurisdictions outside the United States the term “Compliance Enforcement Authority” may designate different entities and / or prescribe different roles.”
Group
Southern Company: Southern Comapny Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Southern Company Operations Compliance
R1.2 Southern suggest that both the EOP-11 and BAL-002-2 SDTs should work together since the proposed language in R1.2 of BAL-002-2 may contradict the revised language of proposed.EOP-011, Attachment 1, regarding maintaining contingency reserves during an EEA condition.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
BAL-002-2 Comments: We would like to thank the drafting for adding the clarification in the Balancing Contingency Event definition that establishes the sudden loss/restoration as that change in generation, import or load that satisfies the reporting criterion within a one-minute sliding window. This is very helpful. However, we would appreciate seeing the explanation contained in the Consideration of Comment in an Application Guideline, Associated Document, etc. section included at the end of the standard. Please hyphenate ’16-second interval’ in the definition of Pre-Reporting Contingency Event ACE Value. Please hyphenate Demand-Side Management in the definition of Contingency Reserve to make it consistent with the term in the Glossary. Responsible Entity does not appear in the NERC Glossary nor is it capitalized in the Functional Model. In fact, the Functional Model encourages the use of the term as ‘responsible entity’. Shouldn’t this standard be changed to reflect that recommended usage? Thank you also for further clarifying that the responsible entity is not subject to compliance with this standard during periods when the responsible entity is in an Energy Emergency Alert Level in which Contingency Reserves have been activated. Hopefully, this

will be understood by the Emergency Operations drafting team. Again, thank you for the clarifying changes to Requirement R1. It is much easier to read than the previous version. In Requirement R1, Part 1.3(ii) hyphenate '105-minute period'. In Requirement R2, the responsible entity is required to maintain Contingency Reserve, averaged over each Clock Hour. Can the drafting team provide any insight into a recommended scan rate for this averaging? Also, a similar average Clock Hour Most Severe Single Contingency (MSSC) is established as the bar for compliance. How often does the drafting team expect MSSC to change? Is this averaging done on a similar basis as Contingency Reserve? In the past, MSSC has been set based on system norms for a given period – for example a year in the existing standard and then modified daily on an availability basis. Does the drafting team really mean an average MSSC for the hour or is it the Real-time value of MSSC during the hour? In the 3rd line of M2, change 'documenting' to 'documented'. Background Document Comments: In the 5th line of the 1st paragraph of the Introduction, change 'are' to 'were'. This paragraph refers to historical events and even though the requirement is still active, past tense would be the preferred usage. Please hyphenate Demand-Side Management in the 4th line of the 1st paragraph under Contingency Reserve to make it consistent with the term in the Glossary. Responsible Entity does not appear in the NERC Glossary nor is it capitalized in the Functional Model. In fact, the Functional Model encourages the use of the term as 'responsible entity'. Shouldn't this document be changed to reflect that usage? The Emergency Operations drafting team has proposed to eliminate the term Energy Deficient Entity in the new EOP-011-1 standard. Shouldn't that terminology be phased out in the Background Document in the 4th line of the 2nd paragraph under Contingency Reserve? In the 4th paragraph under Background and Rationale for Requirement R1, capitalize Parts as in 'R1 Parts 1.2 and 1.3'. Also, delete the 'R' in front of 1.3. In the 3rd line of the same paragraph, use lower case 'standards' or use 'Reliability Standards'. In the 1st line of the 5th paragraph under Background and Rationale for Requirement R1, insert a 'the' between 'by' and 'Consortium'. In the 9th line of the 4th paragraph under Background and Rationale for Requirement R2, capitalize 'Real-time'. The language of the 2nd and 3rd subsequent events in the Attachment 2 example is very confusing. We recommend rewording the 1st line at the top of Page 20 (the 2nd subsequent event in the example) to read '…required ACE recovery being reduced by 400 MW to -400 MW.' Similarly, in the 3rd subsequent event in the 3rd line of the paragraph below the bullets on Page 20, reword the line to read '…required ACE recovery being reduced by another 200 MW to -600 MW.' We recommend that the RSAW be revised to reflect the modified language we have proposed for the standard.
Group
Bonneville Power Administration
Andrea Jessup
Transmission Reliability Standards Group
BPA is in agreement with the proposed standard, however, believes there should be a clarifying comment in requirement R1. In R1, following the second bullet, BPA would like to state: For all subsequent events that occur during the initial Contingency Event Recovery Period, the Pre-Reporting Contingency Event ACE Value for that initial event must be used for the subsequent event(s). BPA has included an example using the Example in Attachment 2 of the NERC BAL-002 Background Document to demonstrate and add clarity to the statement above. The example includes a diagram that will emailed separately to Darrel Richardson (NERC Standards Developer) and Jerry Rust, SDT member.
Individual
Robert Blohm
Keen Resources Ltd.
Consideration of the changes I repeatedly proposed here http://www.robertblohm.com/BAL-002-2 was repeatedly put off by the drafting team. Please consider them now. I proposed the changes here http://www.robertblohm.com/BAL-002-2-Background-Document in the previous comment round and, together with my comments on them in that round, they were never addressed by the drafting team. Please consider them this time.

Standards Announcement Reminder

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Additional Ballot Now Open through October 2, 2014

Now Available

An additional ballot for the **BAL-002-2 – Disturbance Control Performance -Contingency Reserve for Recovery from a Balancing Contingency Event** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are now open through **8 p.m. Eastern on Thursday, October 2, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standards, definitions, implementation plan and associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote will not carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

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 standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

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BAL-002-2

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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 standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **BAL-002-2 – Disturbance Control Performance -Contingency Reserve for Recovery from a Balancing Contingency Event** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, October 3, 2013**.

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
79.94% / 46.73%	76.49% / 54.12%

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 to determine the next steps.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Darrel Richardson.

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Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-002-2
Ballot Period:	9/23/2014 - 10/3/2014
Ballot Type:	Additional
Total # Votes:	271
Total Ballot Pool:	339
Quorum:	**79.94 % The Quorum has been reached**
Weighted Segment Vote:	46.73 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	89	1	29	0.475	32	0.525	0	14	14
2 - Segment 2	10	0.9	3	0.3	6	0.6	0	0	1
3 - Segment 3	75	1	25	0.5	25	0.5	0	10	15
4 - Segment 4	23	1	8	0.444	10	0.556	0	3	2
5 - Segment 5	71	1	26	0.591	18	0.409	0	8	19
6 - Segment 6	53	1	17	0.515	16	0.485	0	9	11
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.3	1	0.1	2	0.2	0	0	2
9 - Segment 9	3	0.1	0	0	1	0.1	0	0	2

10 - Segment 10	8	0.6	3	0.3	3	0.3	0	2	0
Totals	**339**	**6.9**	**112**	**3.225**	**113**	**3.675**	**0**	**46**	**68**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - Support Comments from (Northeast Power Coordinating Council) NPPC
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM's comments)
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)

1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase		
				SUPPORTS THIRD

1	Otter Tail Power Company	Daryl Hanson	Negative	PARTY COMMENTS - (MISO's comments)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted on behalf of PPL NERC Registered Entities)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's Comment)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	

2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	COMMENT RECEIVED
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC & NPCC/RSC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach		
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		
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Interconnection)
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan		
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	Consumers Energy	Richard Blumenstock	Abstain	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by PJM Interconnection)
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supports PJMs comments)
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - Standards Review Committee

				(SRC) of the ISO/RTO Council
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric and Duke Energy)
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates.)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Abstain	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
				SUPPORTS THIRD

3	Potomac Electric Power Co.	Mark Yerger	Negative	PARTY COMMENTS - (PJM Interconnection)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's Comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
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	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
				SUPPORTS THIRD PARTY COMMENTS -

4	Ohio Edison Company	Douglas Hohlbaugh	Negative	(Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light's Paul Haase's Comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative comments submitted by Maryclaire Yatsko)
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko		
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	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC and NYISO
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Abstain	

5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF ACES)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	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		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF comments)
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi		
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	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM comments)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
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	SUPPORTS THIRD PARTY COMMENTS - (Haase, SEattle)

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Posted by Seminole Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
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		
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - ((Northeast Power Coordinating Council) NPPC)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
				SUPPORTS THIRD PARTY

6	Great River Energy	Donna Stephenson	Negative	COMMENTS - (MRO and ACES)
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC RSC Comments
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
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	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
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		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist		
7	Steel Manufacturers Association	James Brew		

8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Robert Blohm	Affirmative	
8	Debra R Warner	Debra R Warner		
8	Energy Mark, Inc.	Howard F. Illian		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Negative	COMMENT RECEIVED - SERC Operating Committee
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

Non-Binding Poll Results

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-14.1 BARC BAL-002-2
Poll Period:	9/23/2014 - 10/3/2014
Total # Opinions:	244
Total Ballot Pool:	319
Summaray Results:	76.49% of those who registered to participate provided an opinion or an abstention; 54.12% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
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	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	

1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NPCC Comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)

1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO's comments)
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted on behalf of PPL NERC Registered Entities)
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	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	

1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
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	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	COMMENT RECEIVED
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach		
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		
3	Avista Corp.	Scott J Kinney	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan		
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NPCC)
3	Consumers Energy	Richard Blumenstock	Abstain	
3	CPS Energy	Jose Escamilla	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - Standards Review Committee (SRC) of the ISO/RTO Council
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos		

3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Omaha Public Power District	Blaine R. Dinwiddie	Abstain	
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	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	SUPPORTS THIRD PARTY COMMENTS - MISO
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)

3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Abstain	
3	Westar Energy	Bo Jones	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller		
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	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
4	Consumers Energy Company	Tracy Goble	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)

4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative comments submitted by Maryclaire Yatsko)
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko		
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		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC and NYISO
5	Consumers Energy Company	David C Greyerbiehl	Abstain	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	

5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF ACES)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Abstain	
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		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF comments)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi		
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	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		

5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
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	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Posted by Seminole Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
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		
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		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	

6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - ((Northeast Power Coordinating Council) NPPC)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (Standards Review Committee (SRC) of the ISO/RTO Council via PJM)
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO and ACES)
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC RSC Comments
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
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	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light)
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		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	EnerVision, Inc.	Thomas W Siegrist		

7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Robert Blohm	Affirmative	
8		Edward C Stein		
8	Debra R Warner	Debra R Warner		
8	Energy Mark, Inc.	Howard F. Illian		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

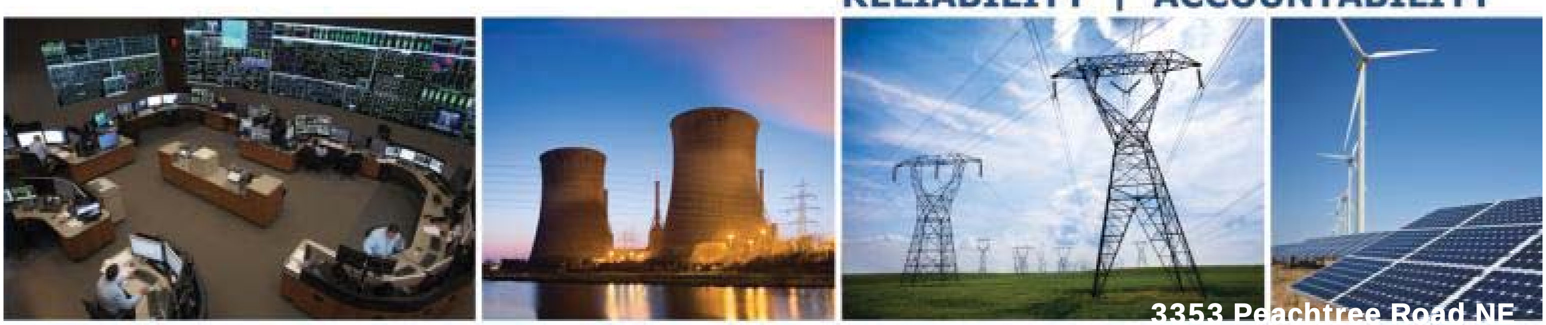
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2010-14.1 BARC – Reserves
BAL-002-2

January 2015

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2010-14.1 Drafting Team thanks all commenters who submitted comments on the proposed revisions to BAL-002-2 The standard was posted for a 45-day formal comment period from August 19, 2014 through October 3, 2014. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 28 sets of responses, including comments from approximately 109 different people from approximately 74 companies representing all 10 Industry Segments..

All comments submitted may be reviewed in their original format on the 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 Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@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

Consideration of Comments

Purpose

The BARC Standard Drafting Team (SDT) appreciates industry's comments on the BAL-002-2 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if an additional comment period and ballot are needed. The following pages are a summary of the comments received and how the SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer to discuss.

NERC Glossary Terms

One commenter felt that the proposed definitions should not be added to the NERC Glossary of Terms and only be reflected in the standard. The SDT believes that by adding these terms to the glossary it will provide consistency in their use and eliminate any misunderstandings that could arise in the future.

Based on Industry comments received the SDT removed the word "Interconnection" from the phrase "Loss of generator Interconnection Facility" from the definition of Balancing Contingency Event.

A couple of Industry commenters wanted to add the term "curtailment of energy transactions" to the definition of Balancing Contingency Event. The SDT disagrees since this is covered in the sub-parts of Requirement R2.

One commenter wanted to remove item "B" from the definition of Balancing Contingency Event. The SDT discussed their comment but decided to leave it in the definition as it provides additional clarity.

One commenter felt that the sub-parts a and b of Part A of the Balancing Contingency Event definition should be eliminated and simply state "Any sudden loss of generation that causes an unexpected change to the responsible entity's ACE". The SDT disagrees with simplifying the definition in this manner. The SDT believes that the detail is necessary to minimize interpretations of the true meaning.

A couple of commenters felt that the reporting thresholds in the Reportable Balancing Contingency Event definition were too high while a couple of other commenters felt that they were too low. The SDT revised the box plots used to set the thresholds to only use loss of a resource. The revised box plots reinforce the SDT's choice of the reporting thresholds for each Interconnection.

Applicability Section

One commenter felt that the term Responsible Entity should not be capitalized since it was not in the NERC Glossary of Terms. The SDT disagrees since the term is defined in the Applicability Section of the standard.

A couple of commenters questioned what the SDT meant by use of the term "active status". The SDT believes that this term provides sufficient clarity and that those BA's and RSG's that allow for a BA to either use the RSG to recover from an event or recover from the event on their own understand the use of the term.

Energy Emergency Alert Level 2 or Level 3

Based on Industry comments received the SDT added Attachment 3 to the Background Document to provide additional information regarding the interaction between BAL-002-2 and Energy Emergency Alerts.

Requirement R1

Based on comments received from the industry the SDT added the phrase "Reliability Coordinator approved" to Requirement R1 Part 1.2 to provide clarity that the Reliability Coordinator was the entity that determined when an Energy Emergency Alert could be established and not the Balancing Authority or the Reserve Sharing Group.

A couple of Industry commenters suggested modifying Requirement R1 Part 1.1 to allow for using an alternate type of calculation rather than CR Form 1. The SDT is trying to provide a consistent method for calculating compliance that can be used globally and therefore decided to leave the language as it is presently written.

A few commenters still did not agree with modifying the present standard. The SDT is attempting to resolve issues that have come up with regards to responding to events greater than MSSC. This need is demonstrated by the request for interpretation that was requested by the NWPP and has been filed with FERC.

One commenter suggested adding the phrase 'beginning at the time of" to Requirement R1 Part 1.3. The SDT disagrees with their suggestion. The SDT believes that the present wording provides the necessary clarity for an entity to understand and be compliant with this part of the requirement.

One commenter suggested that the SDT change the Contingency Event Recovery Period from 15 minutes to 30 minutes. The SDT discussed this comment but decided that since they did not have any empirical evidence to support such a change the recovery period should remain at the 15 minute level.

One commenter questioned when it would be necessary for an entity to use CR Form 1. The form is to be used for every reportable event. The SDT removed any "filing" requirements from the standard as they believe that this is an administrative activity and should not be included in any reliability standard (Paragraph 81).

One commenter wanted Requirement R1 Part 1.2 and 1.3 to be combined. The SDT discussed this at length and decided to leave them as they are presently written since they believe that it provides necessary clarity.

Requirement R2

Based on comments received from the industry the SDT added language to Requirement R2 to provide additional clarity. Specifically, the SDT added language describing periods when an Entity would not be held to compliance with Requirement R2 and the associated recovery period.

Several commenters did not believe that Requirement R2 was necessary and actually created a "commodity obligation". The SDT disagrees and believes the requirement is necessary for reliability and to meet the approach for the FERC directive. The current standard (Requirement R3 part 3.1) requires a BA or RSG to maintain Contingency Reserve at least equal to its MSSC.

Some commenters felt that this standard required an entity to carry reserves in excess of MSSC. The SDT disagrees and feels that the language clearly states that an entity would only be held to compliance for events up to MSSC.

One commenter suggested that the language in Requirement R2 needed to be modified to remove the "clock hour". The SDT disagrees. The SDT believes that removing the "clock hour" language would add an order of complexity to the requirement and increase the data retention requirements. Also, the SDT used the term "clock hour" to allow for the normal fluctuations that occur.

One entity felt that the standard was focusing more on tracking Contingency Reserve rather than how Contingency Reserve could be used. The SDT disagrees with their concern but the SDT did modify the requirement to provide additional clarity on how Contingency Reserve could be used. The SDT also believes that by allowing for the use of Contingency Reserve for other events then an entity would have to be able to track its Contingency Reserve.

One commenter questioned what scan rate should be used. The minimum scan rate is defined in BAL-005-0.2b.

One commenter asked the question if the SDT thought that MSSC could change during the hour and whether they meant for the MSSC averaging to be done in the same manner as Contingency Reserve. The SDT believes that the MSSC could change depending on the conditions the entity is incurring. The SDT is requiring that the averaging be done in the same manner that Contingency Reserve is calculated.

One entity felt that Requirement R2 could allow for gaming in that a BA could d3eclare an EEA simply to be compliant with BAL-002-2. The SDT disagrees with the comment. The SDT notes that the BA does not declare the EEA but they approach the RC to request that an EEA go into effect. The RC has the final say as to whether or not an EEA would be declared.

Measure M2

The SDT modified the language in Measure M2 to provide additional clarity as to how an entity could demonstrate compliance.

One commenter stated that they were not sure as to how to demonstrate compliance. The SDT discussed their concern and decided to modify the measure to provide additional clarity as to how to demonstrate compliance.

Violation Severity Levels (VSLs)

The SDT modified the VSL for Requirement R1 to provide additional clarity.

One commenter felt that the VSL for Requirement R1 should have something to account for an entity not using CR Form 1. The SDT agreed and modified the lower VSL for Requirement R1 to account for not using CR Form 1.

Background Document

Based on industry comments the SDT modified the BAL-002-2 Background Document to provide additional clarity and examples of calculations.

A couple of commenters questioned the development of the reporting thresholds since they appeared to use both loss of a resource and loss of load. The SDT agreed and modified the box plots to only include loss of a resource.

One commenter suggested removing the term Energy Deficient Entity from the Background Document since it is not used in the new EOP-011-1 standard. The SDT discussed this comment but decided to keep the language as it is presently written since the term is used in the present EOP-002-3.1 standard and there is no guarantee that the proposed standard EOP-011-1 will be approved by FERC.

Reliability Standard Audit Worksheet (RSAW)

The current revised Reliability Standards Audit Worksheet (RSAW) will be revised to reflect all modifications made to the present standard.

Standard Development Timeline

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

Description of Current Draft

(Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with parallel ballot, 45-day formal comment period with parallel additional ballot, final ballot.)

Completed Actions	Date
The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal comment period.	May 15, 2007
A revised SAR for Project 2007-05, Reliability Based Controls, was posted for a second 30-day formal comment period.	September 10, 2007
The Standards Committee approved Project 2007-18, Reliability Based Controls, to be moved to standard drafting.	December 11, 2007
The SAR for Project 2007-05, Balancing Authority Controls, was posted for a 30-day formal comment period.	July 3, 2007
The Standards Committee approved Project 2007-05, Balancing Authority Controls, to be moved to standard drafting.	January 18, 2008
The 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.	July 28, 2010
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.	July 13, 2011
The draft standard was posted for 30-day formal industry comment period.	June 4, 2012
The draft standard was posted for 45-day formal industry comment period and initial ballot.	March 12, 2013
The third draft standard was posted for 45-day formal industry comment period and additional ballot.	August 2, 2013

The fourth draft standard was posted for 45-day formal industry comment period and additional ballot.	October 28, 2013
The fifth draft standard was posted for a 45 day formal industry comment period and additional ballot.	August 20, 2014

Anticipated Actions	Date
45-day formal comment period with parallel additional ballot	February/March 2015
Final ballot	April 2015
NERC Board adoption	May 2015

New or Modified Terms Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

- A. Sudden loss of generation:
  - a. Due to
    - i. Unit tripping,
    - ii. Loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
    - iii. Sudden unplanned outage of transmission Facility;
  - b. And, that causes an unexpected change to the responsible entity's ACE;
- B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
- C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW

- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1.3 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3. Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, or dated documentation that demonstrates compliance with Requirement 1.2 and 1.3.

Rationale for Requirement R2: R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and whether it has sufficient response. Additionally, the drafting team understands that the Responsible Entity's available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying operators' hands by removing use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in Real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for issues other than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve.

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or

2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or

2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or

2.4 in a Contingency Reserve Restoration Period; and/or

2.5 in a Contingency Event Recovery Period; and/or

2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

M2. Each Responsible Entity shall have dated documentation that demonstrates compliance with Requirement R2. Evidence of compliance may include, but is not limited to, documenting Contingencies and Energy Emergency Alert Levels through outage records, operator logs, and others.

Compliance may be achieved by demonstrating that:

- Contingency Reserve, averaged over each Clock Hour, meets or exceeds the required Contingency Reserve; or,
- Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period: or,
- the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency Reserve level within the specified period;

  Any shortfall from compliance will be measured as compliance of 100% minus the shortfall's percentage share of MSSC.

If the recording of Contingency Reserve or MSSC is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule in Requirement R2, then compliance with that portion of the hour not excluded may be shown by either determination of the integrated value for that portion of the hour not excluded by the rule or an instantaneous value showing reserves any time during the excluded period.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Real-time Operations**	**Medium**	The Responsible Entity recovered less than 100% but more than 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity recovered 90% or less but more than 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity recovered 80% or less but more than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity recovered 70% or less of required recovery during the Contingency Event Recovery Period.
R2.	**Real-time Operations**	**Medium**	The Responsible Entity had Contingency Reserve but the Clock Hour average amount of Contingency Reserve was less than 100% of MSSC but was greater than or equal	The Responsible Entity had Contingency Reserve but the Clock Hour average amount of Contingency Reserve was less than 90% of MSSC but was greater than or equal	The Responsible Entity had Contingency Reserve but the Clock Hour average amount of Contingency Reserve was less than 80% of MSSC but was greater than or equal	The Responsible Entity did not have Contingency Reserve that was equal to or greater than 70% of MSSC averaged over the Clock Hour.

			to 90% of MSSC as averaged over the Clock Hour.	to 80% of MSSC as averaged over the Clock Hour.	to 70% of MSSC as averaged over the Clock Hour.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

R2.

R3.

R4.

R5.

R6.

R7.

R8.

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

R9.

R10.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

R11.

Rationale

R12. Upon Board approval, the text from the rationale boxes will be moved to this section.

R13.

Standard Development Timeline

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

Description of Current Draft

(Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with parallel ballot, 45-day formal comment period with parallel additional ballot, final ballot.)

Completed Actions	Date
The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal comment period.	May 15, 2007
A revised SAR for Project 2007-05, Reliability Based Controls, was posted for a second 30-day formal comment period.	September 10, 2007
The Standards Committee approved Project 2007-18, Reliability Based Controls, to be moved to standard drafting.	December 11, 2007
The SAR for Project 2007-05, Balancing Authority Controls, was posted for a 30-day formal comment period.	July 3, 2007
The Standards Committee approved Project 2007-05, Balancing Authority Controls, to be moved to standard drafting.	January 18, 2008
The 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.	July 28, 2010
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.	July 13, 2011
The draft standard was posted for 30-day formal industry comment period.	June 4, 2012
The draft standard was posted for 45-day formal industry comment period and initial ballot.	March 12, 2013
The third draft standard was posted for 45-day formal industry comment period and additional ballot.	August 2, 2013

The fourth draft standard was posted for 45-day formal industry comment period and additional ballot.	October 28, 2013
The fifth draft standard was posted for a 45 day formal industry comment period and additional ballot.	August 20, 2014

Anticipated Actions	Date
45-day formal comment period with parallel additional ballot	February/March 2015
Final ballot	April 2015
NERC Board adoption	May 2015

New or Modified Terms Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator ~~Interconnection~~ Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the S~~s~~ink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW

- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16--second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand--Side Management (DSM), Interruptible Load and unloaded generation.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1.3 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1. All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a~~n~~ Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3. Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1, or dated documentation that demonstrates compliance with Requirement 1.2 and 1.3.

Rationale for Requirement R2: R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and whether it has sufficient response. Additionally, the drafting team understands that the Responsible Entity's available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying operators' hands by removing use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in Real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for issues other than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve.

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is~~ in~~: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or

2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or

2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or

2.4 in a Contingency Reserve Restoration Period; and/or

2.5 in a Contingency Event Recovery Period; and/or

2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

M2. Each Responsible Entity shall have dated documentation that demonstrates compliance with Requirement R2.~~, e~~ Evidence of compliance may include, but is not limited to, documenting Contingencies and Energy Emergency Alert Levels through outage records~~, an Energy Emergency Alert Level under which Contingency Reserves have been activated with communication from their RC~~, operator logs, and others.

Compliance may be achieved by demonstrating that:

- Contingency Reserve, averaged over each Clock Hour, meets or exceeds the required Contingency Reserve; or,
- Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period: or,
- the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency Reserve level within the specified period;

Any shortfall from compliance will be measured as compliance of 100% minus the shortfall's percentage share of MSSC.

If the recording of Contingency Reserve or MSSC is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule in Requirement R2, then compliance with that portion of the hour not excluded may be shown by either determination of the integrated value for that portion of the hour not excluded by the rule or an instantaneous value showing reserves any time during the excluded period.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~1.4. Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.5.~~1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

~~A Responsible Entity is not subject to compliance with this standard in any period during which the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated.~~

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Real-time Operations**	**Medium**	The Responsible Entity recovered ~~partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered~~ less than 100% but more than 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity recovered ~~partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered~~ 90% or less but more than 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity recovered ~~partially from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period but recovered~~ 80% or less but more than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity recovered 70% or less of required recovery during the Contingency Event Recovery Period.
R2.	**Real-time Operations**	**Medium**	The Responsible Entity had Contingency	The Responsible Entity had Contingency	The Responsible Entity had Contingency	The Responsible Entity did not have

			Reserve but the Clock Hour average amount of Contingency Reserve was less than 100% of MSSC but was greater than or equal to 90% of MSSC as averaged over the Clock Hour.	Reserve but the Clock Hour average amount of Contingency Reserve was less than 90% of MSSC but was greater than or equal to 80% of MSSC as averaged over the Clock Hour.	Reserve but the Clock Hour average amount of Contingency Reserve was less than 80% of MSSC but was greater than or equal to 70% of MSSC as averaged over the Clock Hour.	Contingency Reserve that was equal to or greater than 70% of MSSC averaged over the Clock Hour.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

R2.

R3.

R4.

R5.

R6.

R7.

R8.

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

R9.

R10.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

R11.

Rationale

R12. Upon Board approval, the text from the rationale boxes will be moved to this section.

R13.

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.
C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities
N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute.

A. Sudden loss of generation:
   a. Due to
      i. Unit tripping,
      ii. Loss of generator ~~Interconnection~~ Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's electric system, or
      iii. Sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and load on the Interconnection.

C. Sudden restoration of a load that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the ~~s~~Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event resulting in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period beginning at the time that the resource output begins to decline within the first one-minute interval that defines a Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16~~-~~-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). The capacity may be provided by resources such as Demand~~-~~-Side Management (DSM), Interruptible Load and unloaded generation.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Comment Form

Project 2010-14.1 Balancing Authority Reliability-based Control

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Please do not use this form to submit comments on the proposed revisions to BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event. Comments must be submitted using the electronic comment form by 8 p.m. **March 16, 2015.** If you have questions please contact Darrel Richardson (email) or by telephone at (609) 613-1848.

Background Information:
Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard.

- Modified Requirement R1 to provide additional clarity.
- Modified Requirement R2 and Measure M2 to provide additional clarity and allow for the use of Contingency Reserve for other than a Balancing Contingency Event. Also, defined other uses for Contingency Reserves.
- Added rationale supporting Requirements R1 and R2.
- Modified the BAL-002-2 Background Document.
    - Modified the body of the document to provide additional clarity.
    - Modified the charts in Attachment 1 to use only loss of resource events and added events for 2014.
    - Added examples for compliance to Requirement R1.
    - Added Attachment 3 which discusses use of Contingency Reserves during an Energy Emergency Alert.

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.

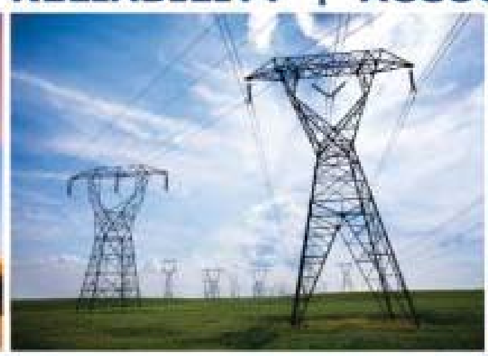
1. **Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.**

   Comments:

BAL-002-2
Background Document

January 2015

RELIABILITY | ACCOUNTABILIT



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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. The suite of NERC Standard work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard, (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there have been 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during the real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002), this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event. Without incurring a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve to the extent it drops below MSSC without violating NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to be exempt from R2 if in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserves available provided that the Responsible Entity has made preparations for interruption of Firm

Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. Also, to assure the system operator has the necessary flexibility to address the transition from normal operations (BAL-002) into emergency operations (EOP) the drafting team elected to allow the Responsible entity to be exempt from R2 during one or more of the following periods when the Responsible Entity is:

- using its Contingency Reserve for Contingencies that are not Balancing Contingency Events;
- responding to an Operating Instruction requiring the use of Contingency Reserve;
- resolving the exceedance of a System Operating Limit or IROL that requires the use of Contingency Reserve; and,
- in a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period.

For additional technical justification for exempting periods from R2 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 3.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- Zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery:

(i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative): however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3 Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within that 105 minute period.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance. The drafting team has included Attachment 2 illustrating an example of the calculation for Requirement R1.

In addition, the standard drafting team (SDT) through R1 Parts 1.2 and 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.2, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. A fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:
  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
  - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.
- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. “near”) Events on a Responsible Entity’s Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

- If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
- If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
- If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

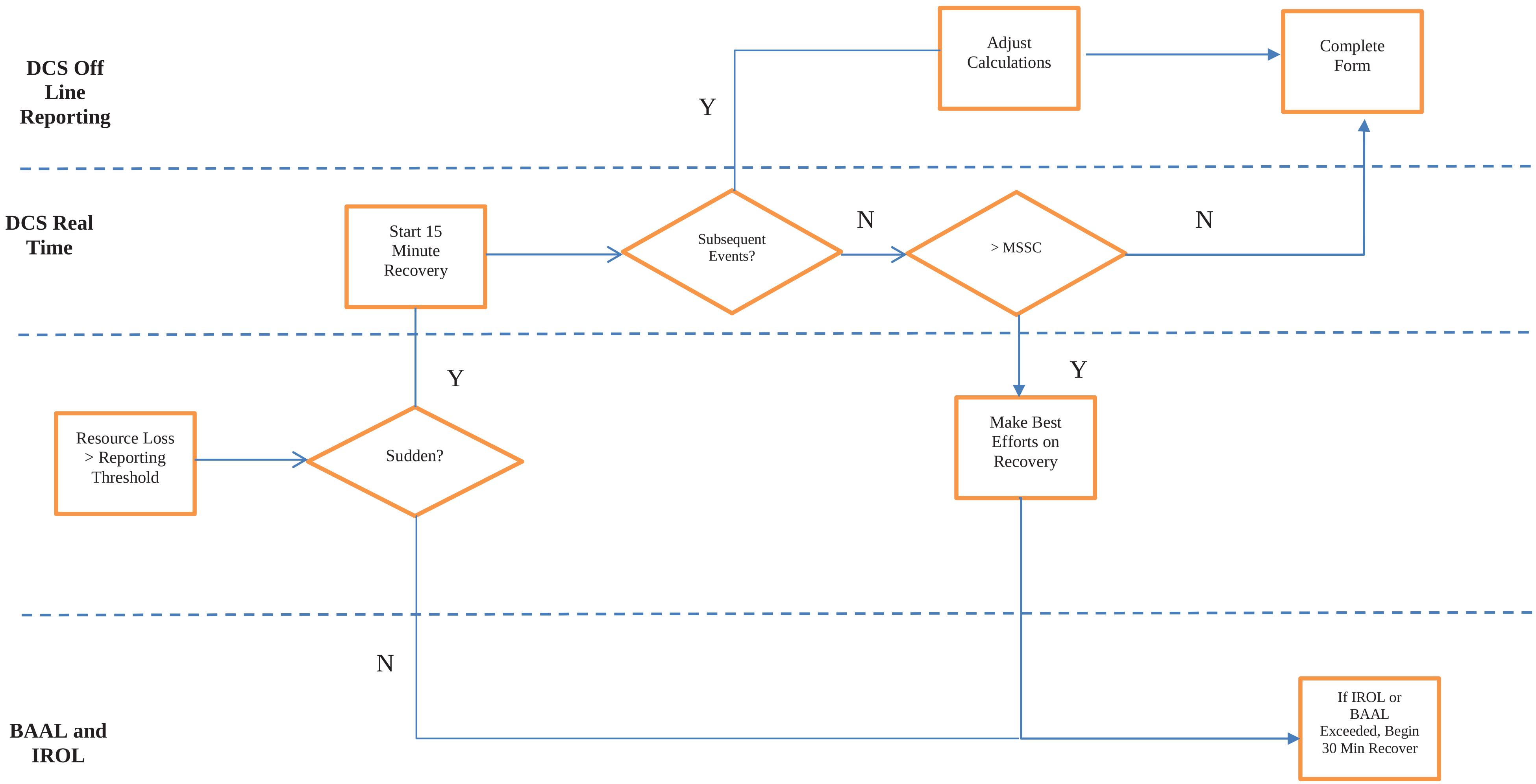
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is:

2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or

2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or

2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or

2.4 in a Contingency Reserve Restoration Period; and/or

2.5 in a Contingency Event Recovery Period; and/or

2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and whether it has sufficient response. Additionally, the drafting team understands that the Responsible Entity’s available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying operators' hands by removing use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in Real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for issues other than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve.

Attachment 1

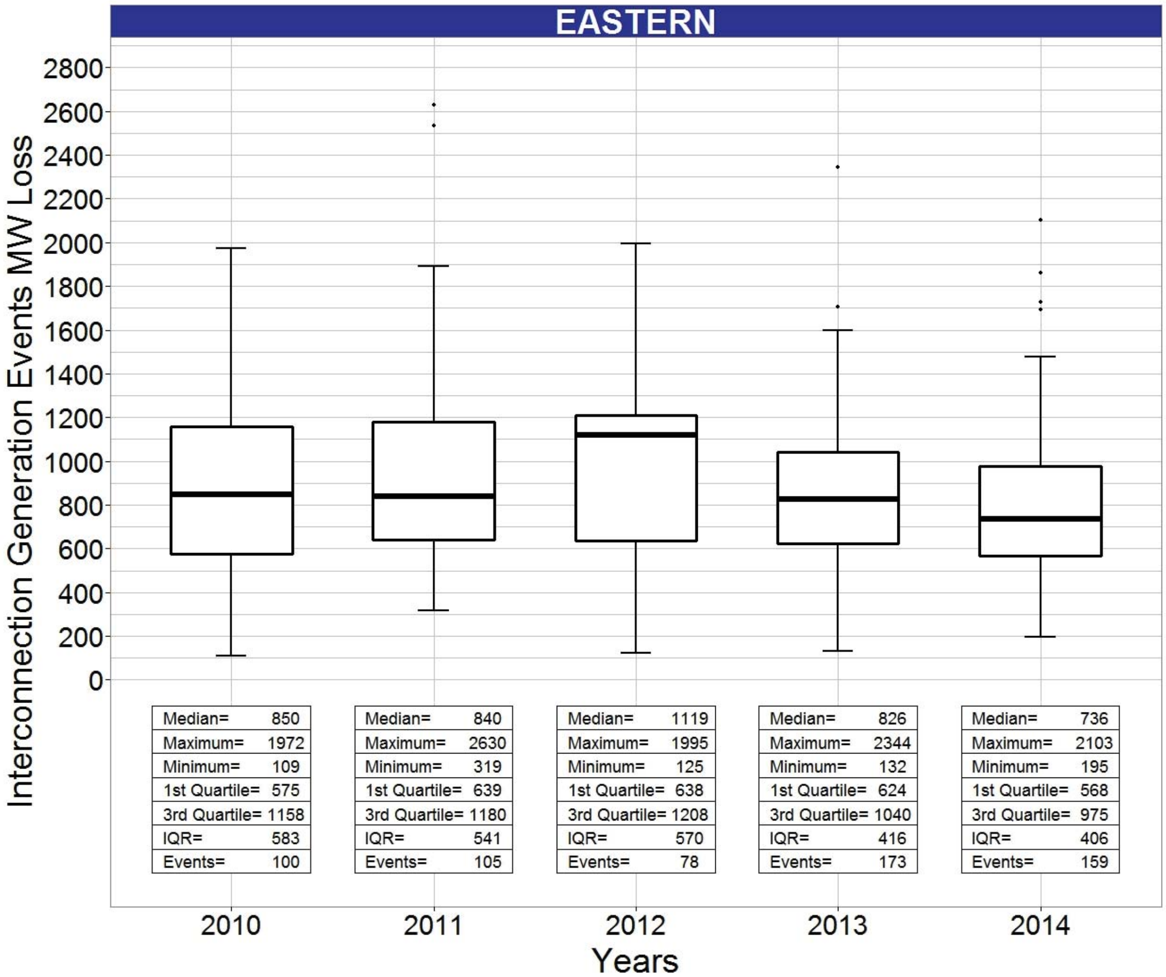
NERC Interconnections 2009-2013

Frequency Events Loss MW Statistics

For: NERC BARC Standard Drafting Team

Prepared by: CERTS

Date: October 15, 2013


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
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Events= 78
Median= 826
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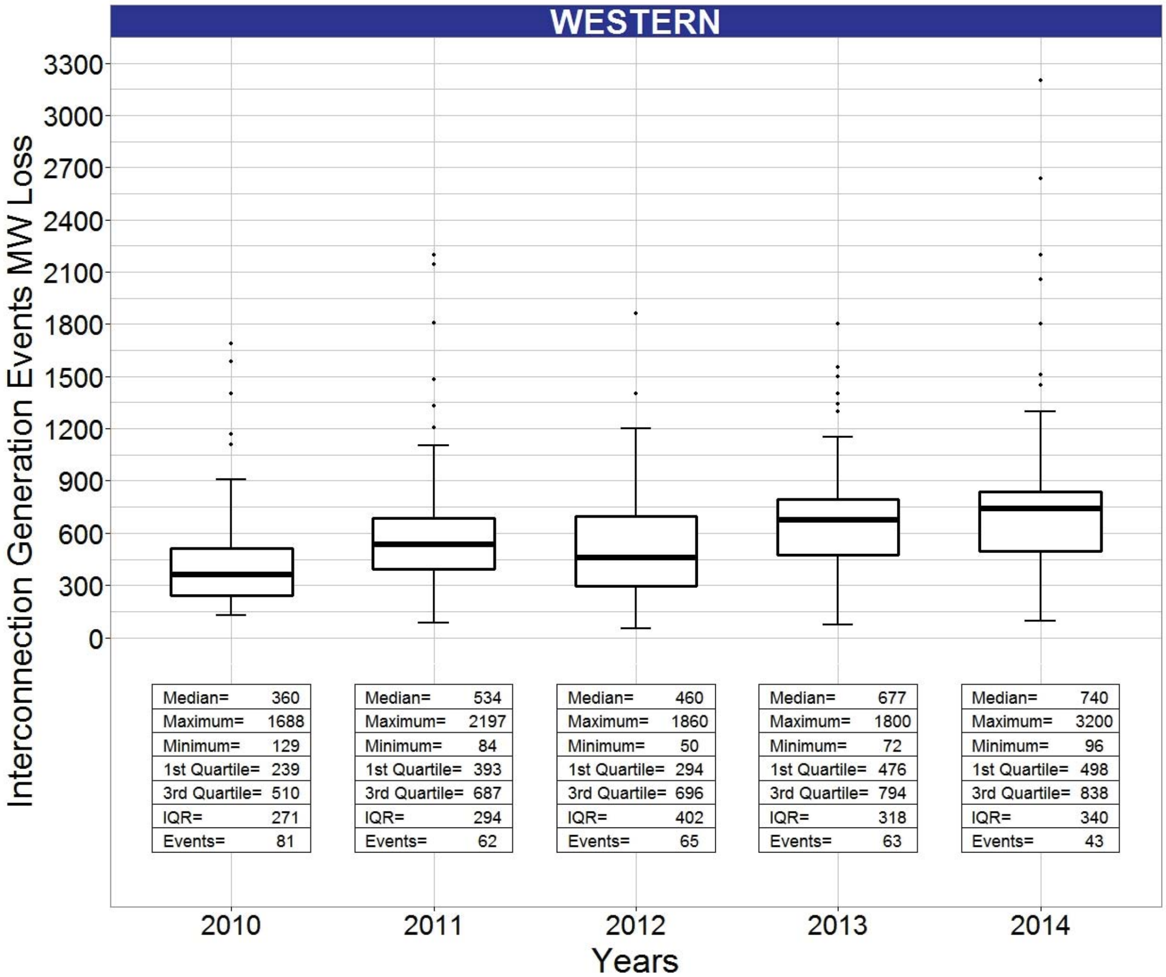
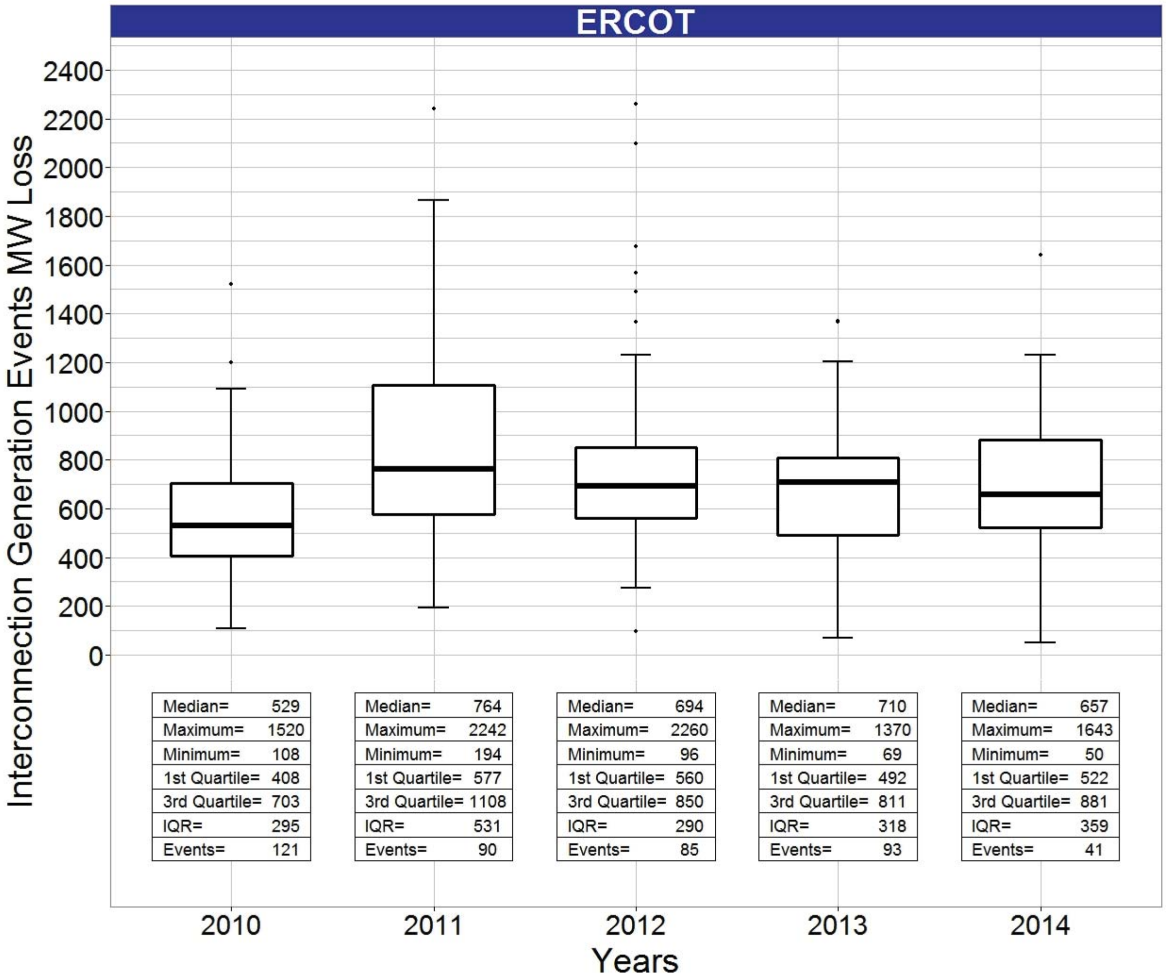
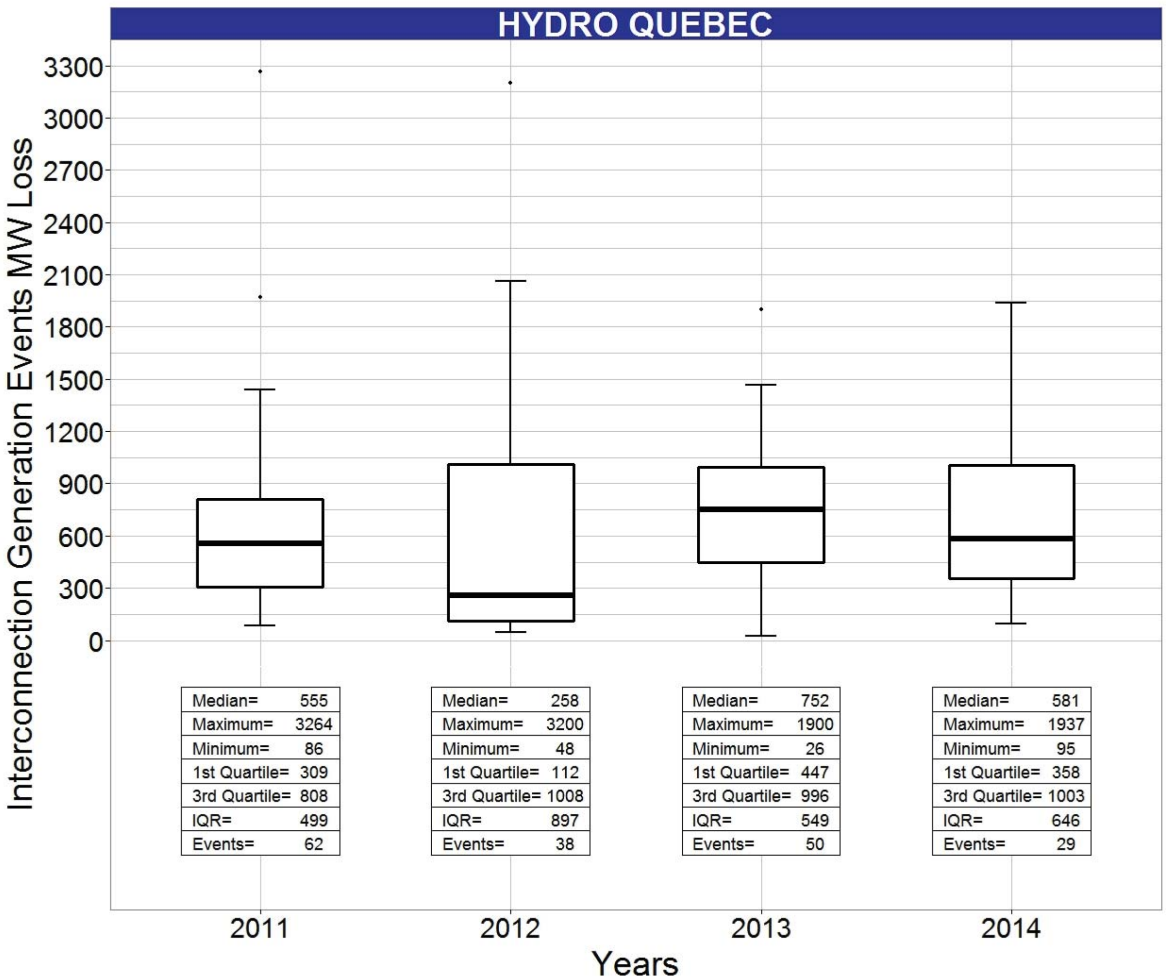
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

BAL-002-2 R1 Example

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

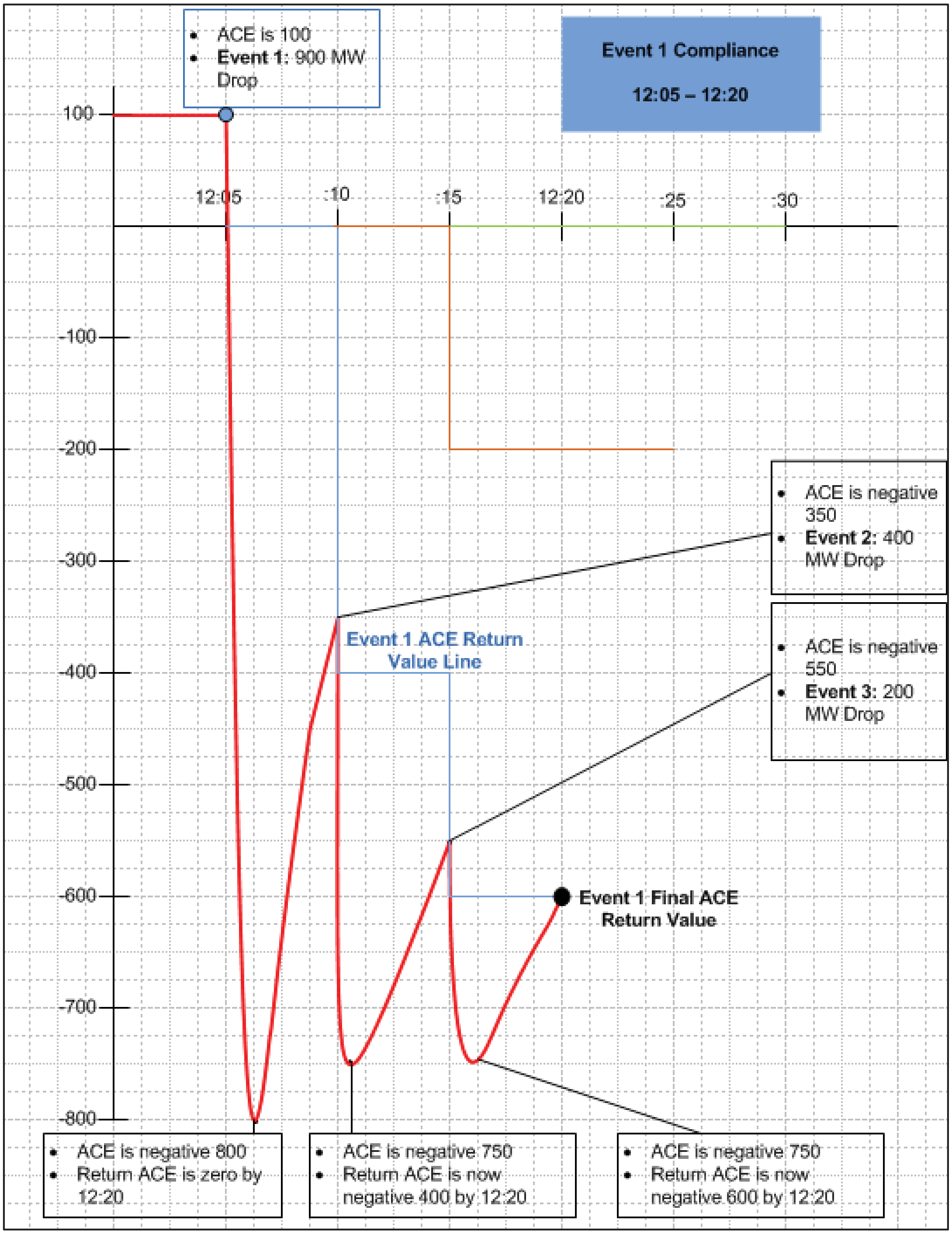
- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

To illustrate the above requirement the following scenario of three Balancing Contingency Events, and compliance for each event, is provided. It is assumed in this scenario that the reportable event threshold is 200 MW.

Event 1 Compliance



- Responsible Entity Pre-Reporting Contingency Event ACE Value is 100 MW
- Time of the Balancing Contingency Event - 12:05
- Size of the Balancing Contingency Event - 900 MW
- Responsible Entity MSSC - 2,000 MW

- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery of Event 1 by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.

However, if the Responsible Entity experienced another Contingency Event (Event 2) based upon the following:

- ACE had recovered to negative 350 – prior to Event 2
- Time of the Contingency Event - 12:10
- Size of the Contingency Event - 400 MW
- Responsible Entity Reporting ACE Value at 12:10 – negative 750

At the time of Event 2, the Responsible Entity would reduce the value of its required recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2), thus lowering the required recovery value of ACE to negative 400 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Event 2, by returning its Reporting ACE to at least a negative 400 MW by 12:20.

Now if the Responsible Entity experienced an additional Contingency event (Event 3) prior to 12:20 namely:

- ACE had recovered to negative 550 MW – prior to Event 3
- Time of the Contingency Event - 12:15
- Size of the Contingency Event - 200 MW
- Responsible Entity Reporting ACE Value at 12:15 – negative 750

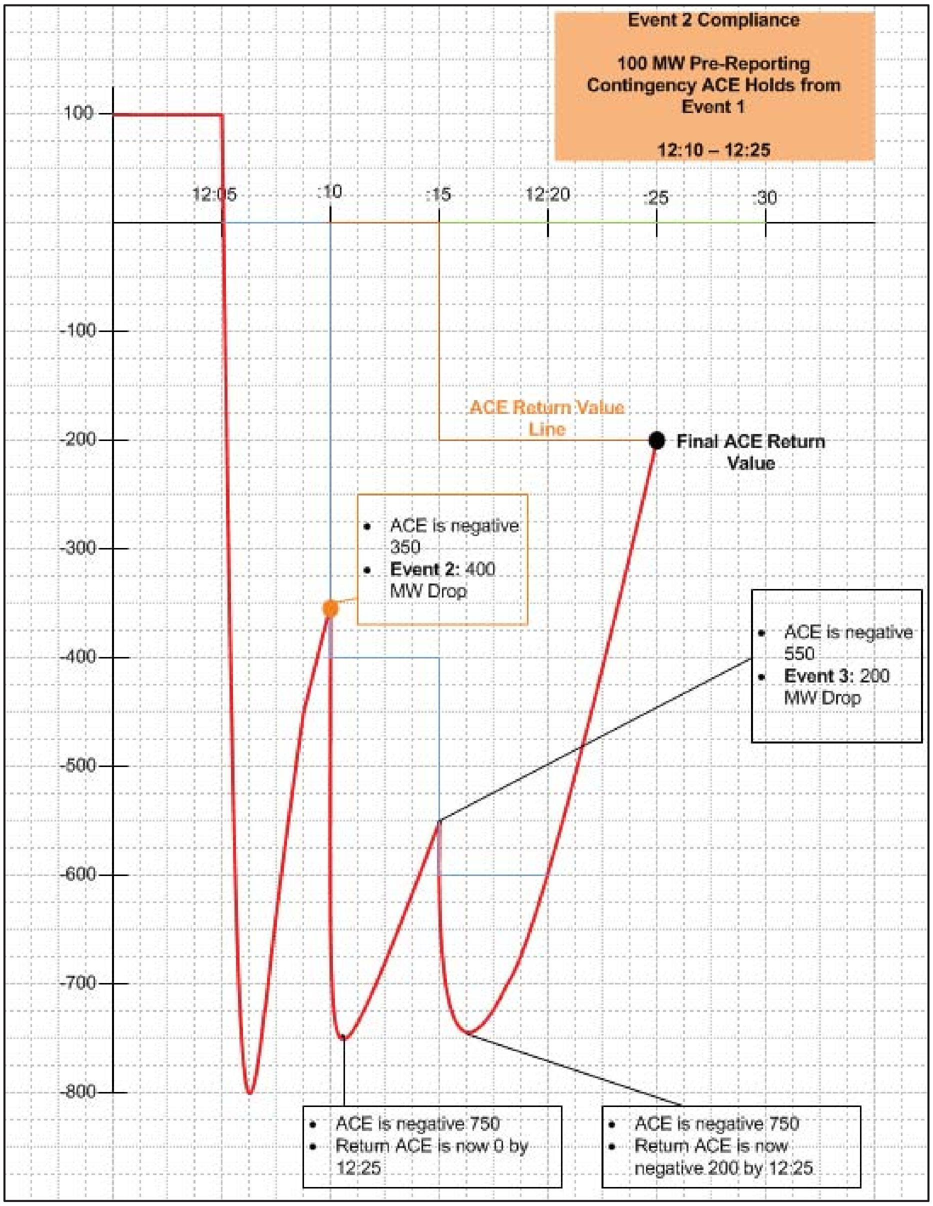
At the time of Event 3, the Responsible Entity would reduce the value of its required ACE recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2) and the Contingency Event at 12:15 (Event 3), thus lowering the required ACE recovery value to negative 600 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Events 2 and 3 by returning its Reporting ACE to at least a negative 600 MW by 12:20.

The Responsible Entity must show compliance for all events that might occur during the Contingency Event Recovery Period (Event 1). Event 2 and Event 3 from the example above would demonstrate compliance in a similar fashion as was demonstrated for Event 1 above. Each would have its own unique Contingency Event Recovery Period as defined by the start of the respective contingency event (i.e. Event 2's Contingency Event Recovery Period would begin at 12:10 and end at 12:25; Event 3's Contingency Event Recovery Period would begin at 12:15 and end at 12:30). The required ACE Value (0 MW) of recovery from Events 1; the required ACE Value (-200 MW) of Recovery from Event 2 would be the required Value (0 MW) of

Recovery from final Event 3) minus the size of Event 3 (200 MW), while the required ACE Value (-600 MW) of Recovery from Event 1 would be the required Value (0MW) of Recovery from final Event 3 minus the size (600 MW) of the events 2 (400 MW) & 3 (200 MW) subsequent to Event 1.

The following demonstrates the logic used for compliance with Event 2 (from 12:10 – 12:25, including Event 3).

Event 2 Compliance



Responsible Entity's required ACE Value of recovery from Event 2 is 0 MW (the same as it was from the pre-existing initial Contingency Event 1 prior to any adjustment for Event 2)

- Time of the Balancing Contingency Event - 12:10
- Size of the Balancing Contingency Event - 400 MW
- Responsible Entity MSSC - 2,000 MW
- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery from Event 2 by returning its Reporting ACE to Event 1's prior, unadjusted Pre-Reporting Contingency Event ACE value of 0 MW within the Contingency Event Recovery Period, or by 12:25.

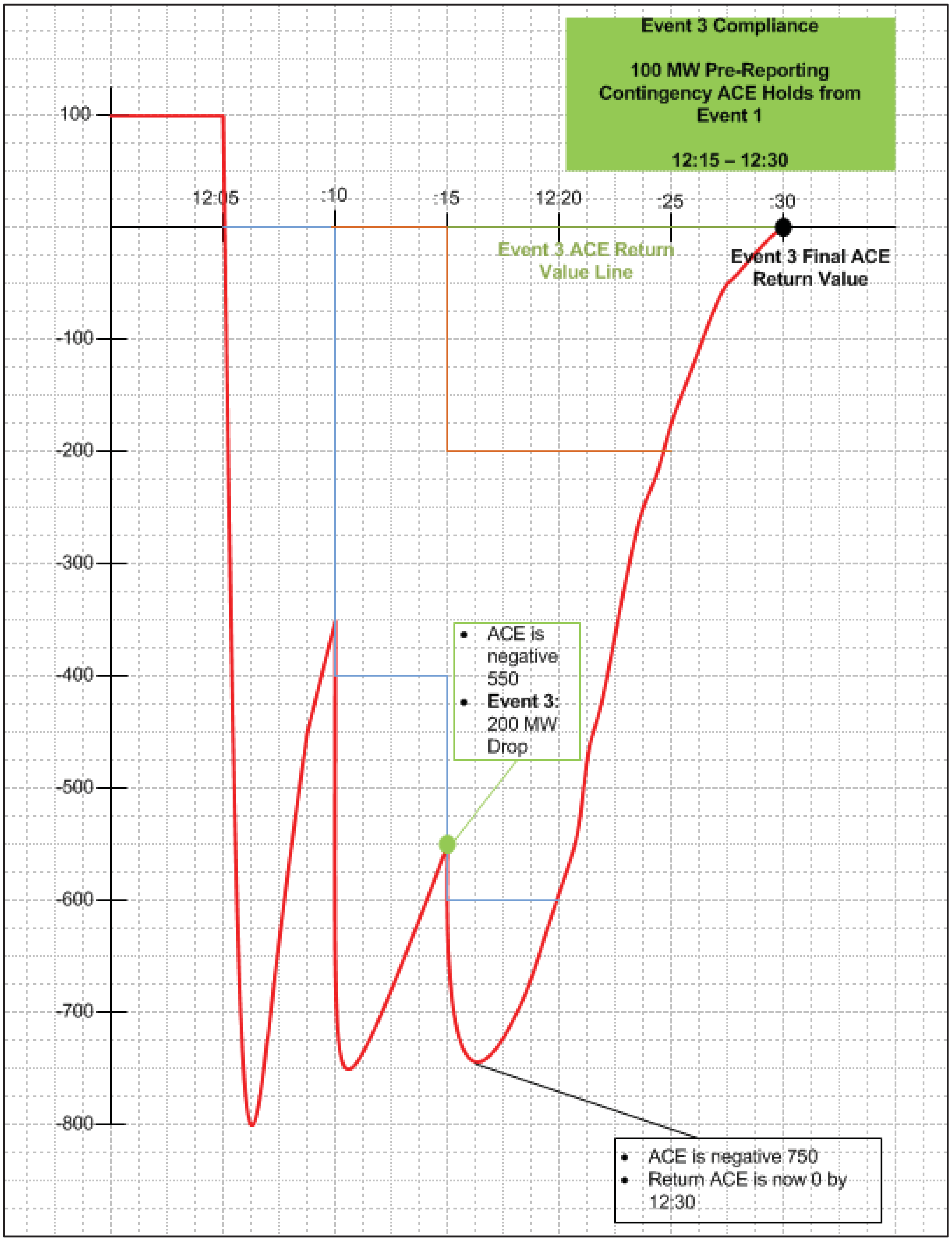
However, the Responsible Entity experienced another Contingency Event (Event 3) based upon the following:

- ACE had recovered to negative 550 – prior to Event 3
- Time of the Contingency Event - 12:15
- Size of the Contingency Event - 200 MW
- Responsible Entity Reporting ACE post Contingency Event – negative 750

At the time of Event 3, the Responsible Entity would reduce the value of its required recovery from the Balancing Contingency Event 2 by the size of Contingency Event 3 at 12:15, thus lowering the required ACE recovery from Event 2 to negative 200 MW. The Responsible Entity would demonstrate recovery from both Balancing Contingency Event 1 and Balancing Contingency Event 2, taking in to account Event 3, by returning its Reporting ACE to at least a negative 200 MW by 12:30.

The following demonstrates the logic used for compliance following Event 3 (from 12:15 – 12:30).

Event 3 Compliance



The Responsible Entity's required ACE Value of recovery from final Event 3 is 0 MW (the same as it was from the initial Balancing Contingency Event 1 prior to any subsequent events)

- Time of the Balancing Contingency Event - 12: 15
- Size of the Balancing Contingency Event - 200 MW
- Responsible Entity MSSC - 2,000 MW
  Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery of final Event 3 by returning its Reporting ACE to the 0 MW ACE value of 0 MW of recovery from the initial Event 1 within the Contingency Event Recovery Period, or by 12:30.

The above examples illustrate the minimum response for compliance. Actual events and recoveries will differ because of matters such as, but not limited to, Contingency Reserve being deployed differently.

Attachment 3

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

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[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

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4 Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

5 Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

6 Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

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[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

BAL-002-2
Background Document

January 2015

RELIABILITY | ACCOUNTABILIT

Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [~~(~~Area Control Error (ACE) must return to zero within 10 minutes following a disturbance~~)~~] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were~~are~~ required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available ~~at all times~~ to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and ~~is~~ a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple of a methodology to adequately address all of these interactions. The suite of NERC Standard work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard, (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL ~~will~~ allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when~~for~~ events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 ~~will~~ requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may ~~require~~ prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units ~~(typically N-1-1 or greater)~~ were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 only address events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and R~~r~~equirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there have been 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. ~~When~~ ~~E~~Eevaluati~~ng~~on of the data illustrates~~,~~ events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, ~~without~~ regardless of ~~to~~ the size of a Balancing Authority or RSG and ~~without respect to~~ of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity ~~if they have~~ that has more stringent standards which require contingency reserve greater than MSSC.

Background

~~This section discusses the new definitions associated with BAL-002-2.~~Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

~~The purpose of~~ BAL-002-2 applies during the real-time operations ~~and is~~ to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event~~.~~.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways~~manners~~ leaving the ability to measure compliance ~~up to~~in the eye of the beholder. ~~By~~ ~~I~~Iincluding the specific definition~~, it~~ allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure~~s~~ the intent of the FERC~~'s~~ requirement is met.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of~~for~~ MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, ~~it~~ this event is unlikely~~impossible for this event~~ to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is ~~primarily~~ focused primarily on generation and not sufficiently on Demand~~-~~-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002), this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and comple~~i~~ment each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 ~~requires~~include deployment of all Operating Reserve which includes Contingency Reserve. An Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, without incurring a Balancing Contingency Event. Without incurring a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve to the extent it drops below MSSC without violating ~~the~~ NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to be exempt from R2 if in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserves available provided that~~have been activated or where~~ the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection.~~is unable to meet Contingency Reserve requirements due to system conditions.~~

Also, to assure the system operator has the necessary flexibility to address the transition from normal operations (BAL-002) into emergency operations (EOP) the drafting team elected to allow the Responsible entity to be exempt from R2 during one or more of the following periods when the Responsible Entity is:

- using its Contingency Reserve for Contingencies that are not Balancing Contingency Events;
- responding to an Operating Instruction requiring the use of Contingency Reserve;
- resolving the exceedance of a System Operating Limit or IROL that requires the use of Contingency Reserve; and,
- in a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period.

For additional technical justification for exempting periods from R2 to facilitate~~applicability of~~ transitioning ~~suddenly~~ from normal operations into emergency operations please refer to Attachment 3.

~~to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3.~~

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of~~for~~ the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in ~~from~~ the existing standard. R5.1 and R5.2 mix~~are~~ definitions ~~mixed~~ with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has~~must~~ added the definition of ~~the~~ Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- Zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

or

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE was negative): however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1.

1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.

1.3 Requirement R1 (in its entirety) does not apply:

- (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or
- (ii) after multiple Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within that 105 minute period. ~~,~~

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes ~~a ceiling for~~ the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows

Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1 allows for measurement of performance. The drafting team has included Attachment 2 illustrating an example of the calculation for Requirement R1.

In addition, the standard drafting team (SDT) through R1 P~~p~~arts 1.2 and ~~R~~1.3 has clearly identified when R1 is not applicable. By including R1 P~~p~~art 1.2, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. A fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, ~~one could demonstrate~~reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of ~~the~~ FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's~~(s)~~ Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team ~~only~~ used only loss of resource~~the positive~~ events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved~~amount of its Contingency Reserve available and whetherdoes it hasve sufficient response~~. ~~The VSL takes these factors into account.~~

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly~~To determine compliance with R1~~, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:
  - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
  - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. “near”) Events on a Responsible Entity’s Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

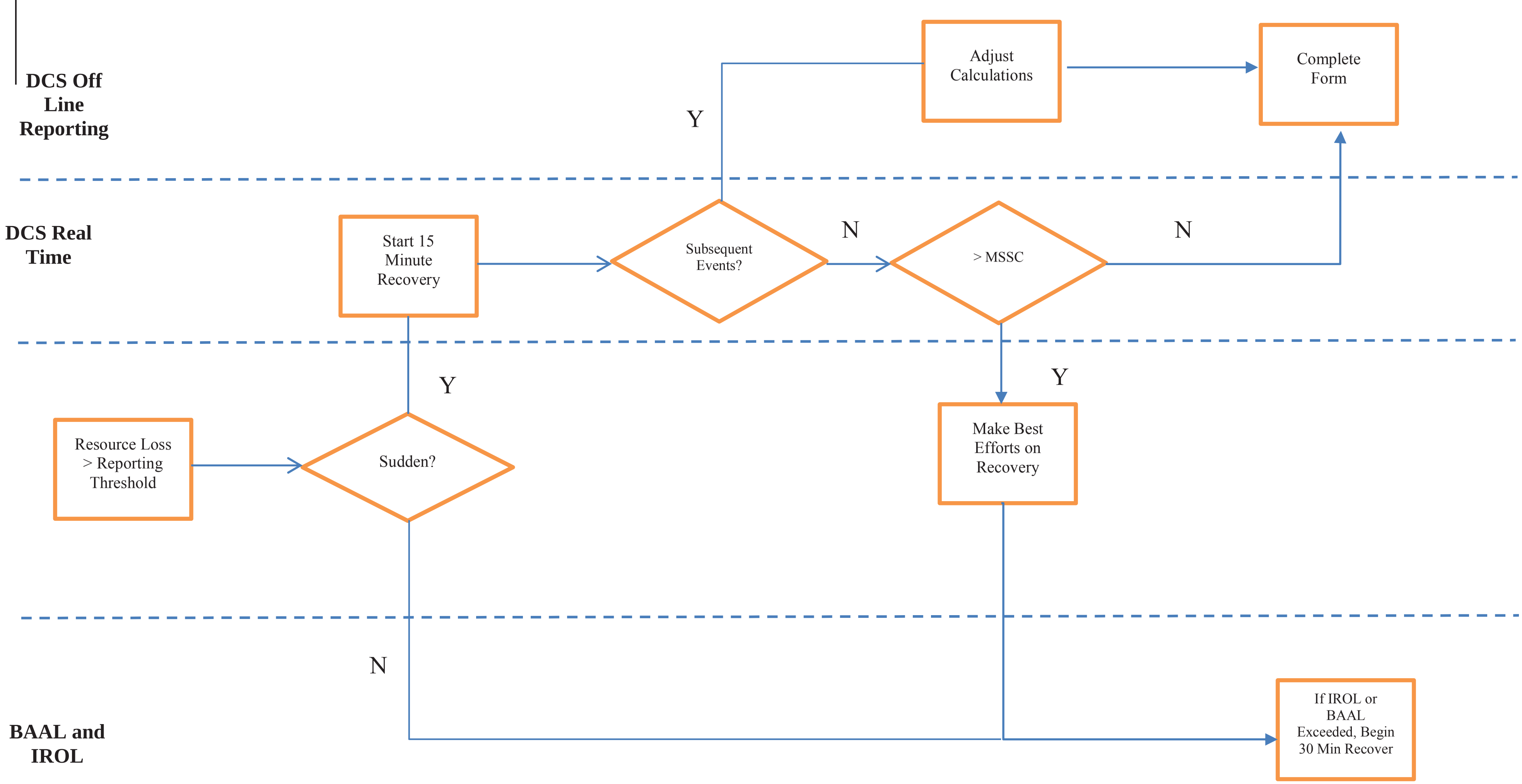
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is:

2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or

2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or

2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or

2.4 in a Contingency Reserve Restoration Period; and/or

2.5 in a Contingency Event Recovery Period; and/or

2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

- ~~using its Contingency Reserve for Contingencies that are not Balancing Contingency Events.~~
- ~~responding to an Operating Instruction requiring the use of Contingency Reserve;~~
- ~~resolving the exceedance of a System Operating Limit or IROL that requires the use of Contingency Reserve; and,~~
- ~~in a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period.~~

~~*Any time an entity deploys Contingency Reserve for any of the above reasons and its remaining Contingency Reserve is below the required minimum level, the entity will have a period not to exceed 90 minutes from the time the amount of Contingency Reserves drops below the level required in this R2 to restore its reserves to meet R2.*~~

~~in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection.~~

~~The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in:~~

~~a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or~~

~~a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or~~

~~an Energy Emergency Alert Level under which Contingency Reserves have been activated.~~

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to the applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that the Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and whether~~does~~ it has~~have~~ sufficient response. Additionally, the drafting team understands that the Responsible Entity's available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.

The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying ~~the~~ operators' hands by removing ~~the~~ use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in R~~r~~eal-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for ~~other~~ issues other than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve ~~for only other Contingencies, thus bounding the use of Contingency Reserve to only the N-1 conditions~~.

Attachment 1

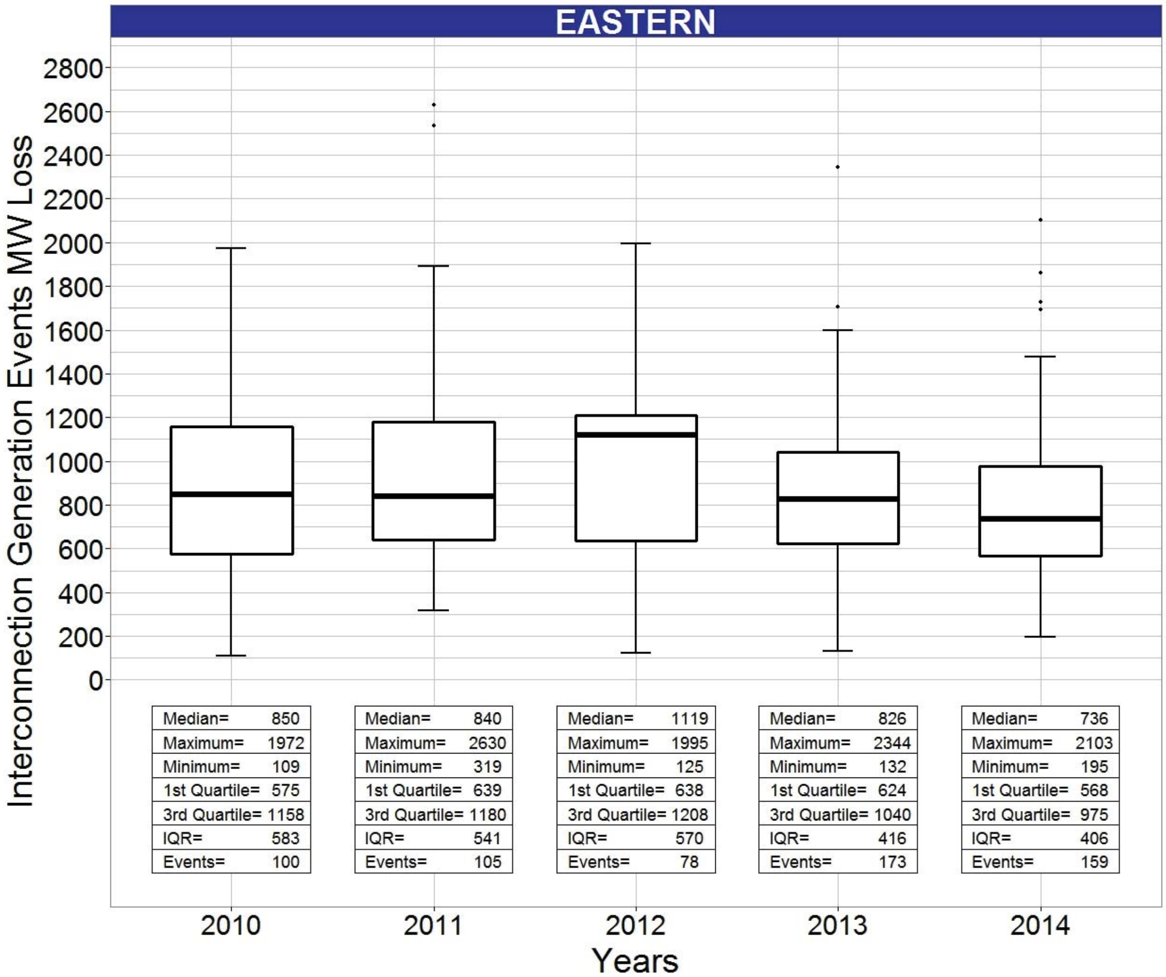
NERC Interconnections 2009-2013

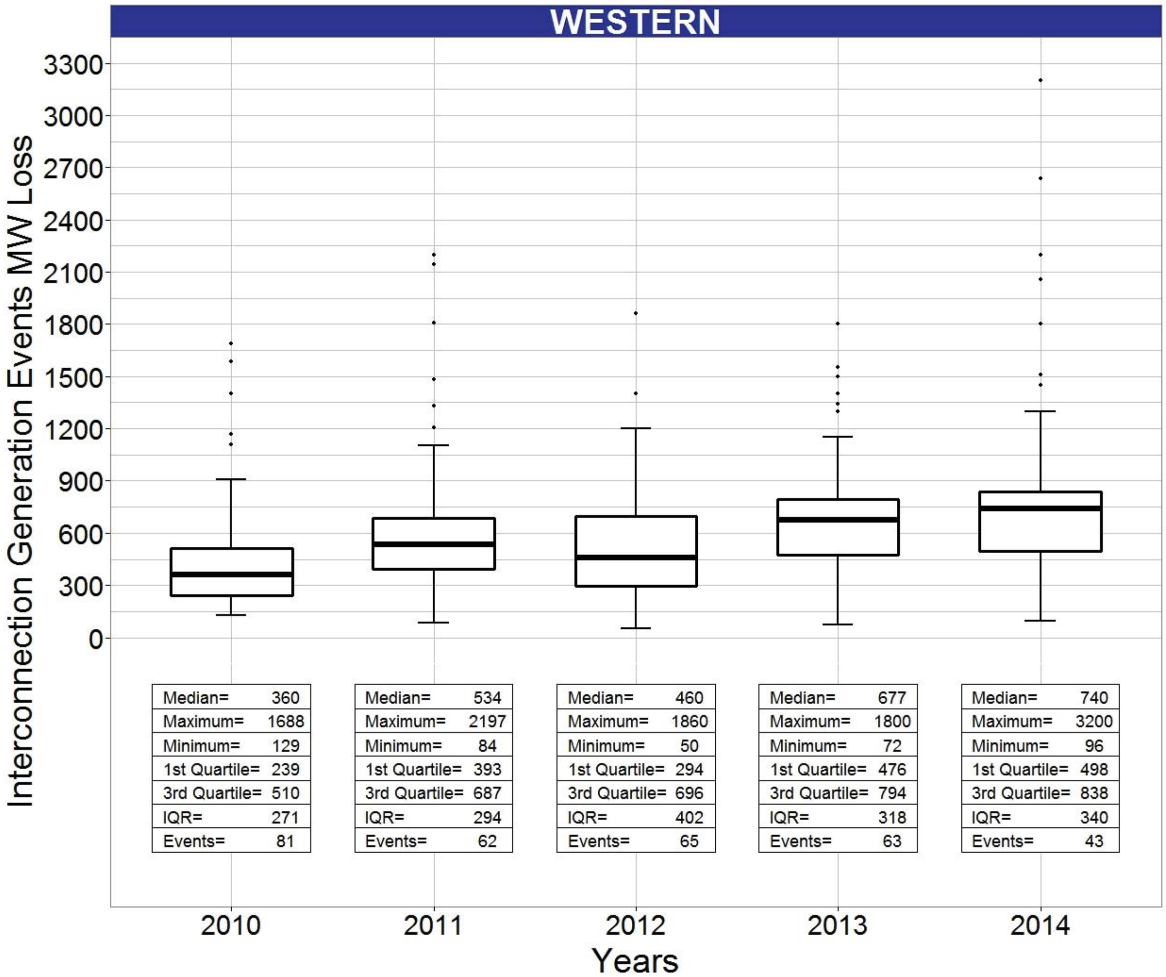
Frequency Events Loss MW Statistics

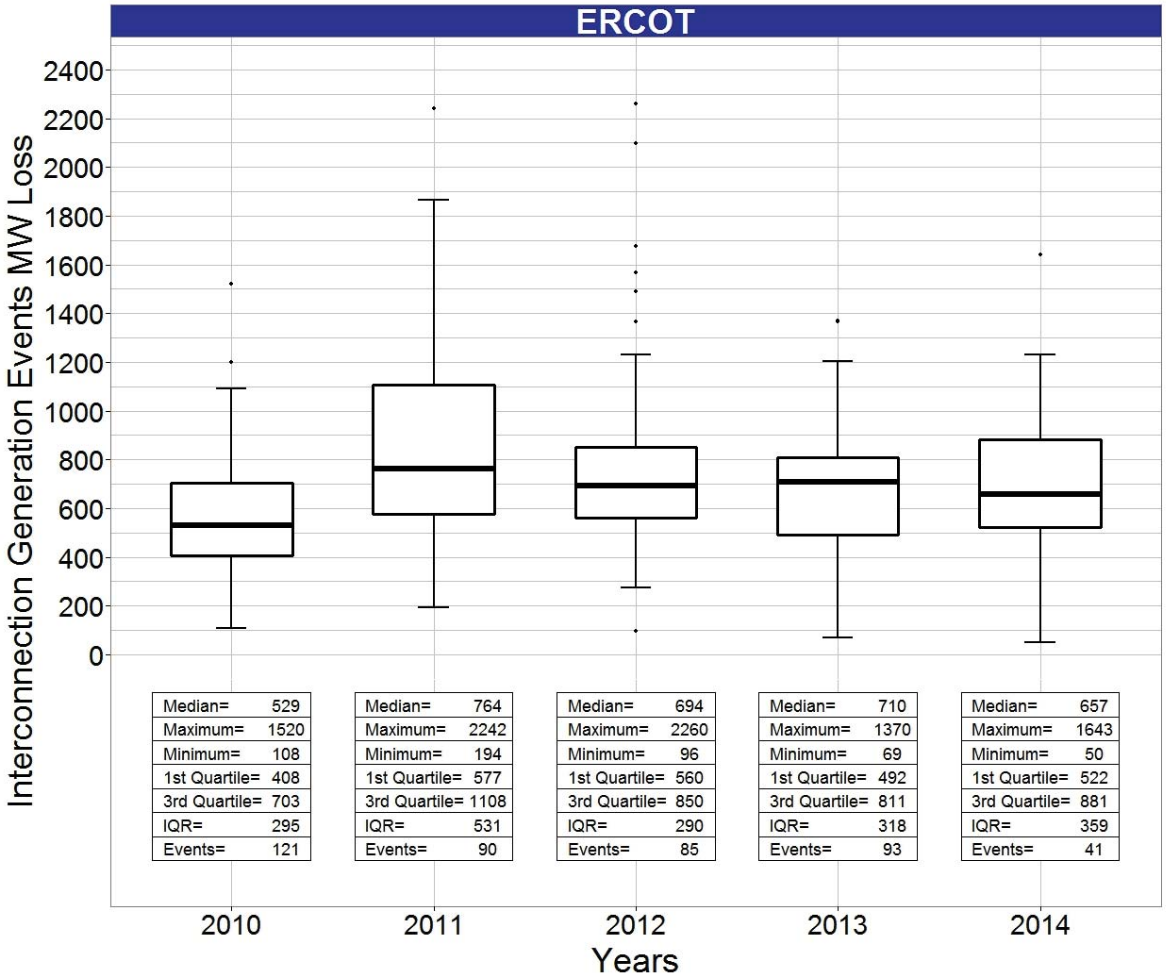
For: NERC BARC Standard Drafting Team

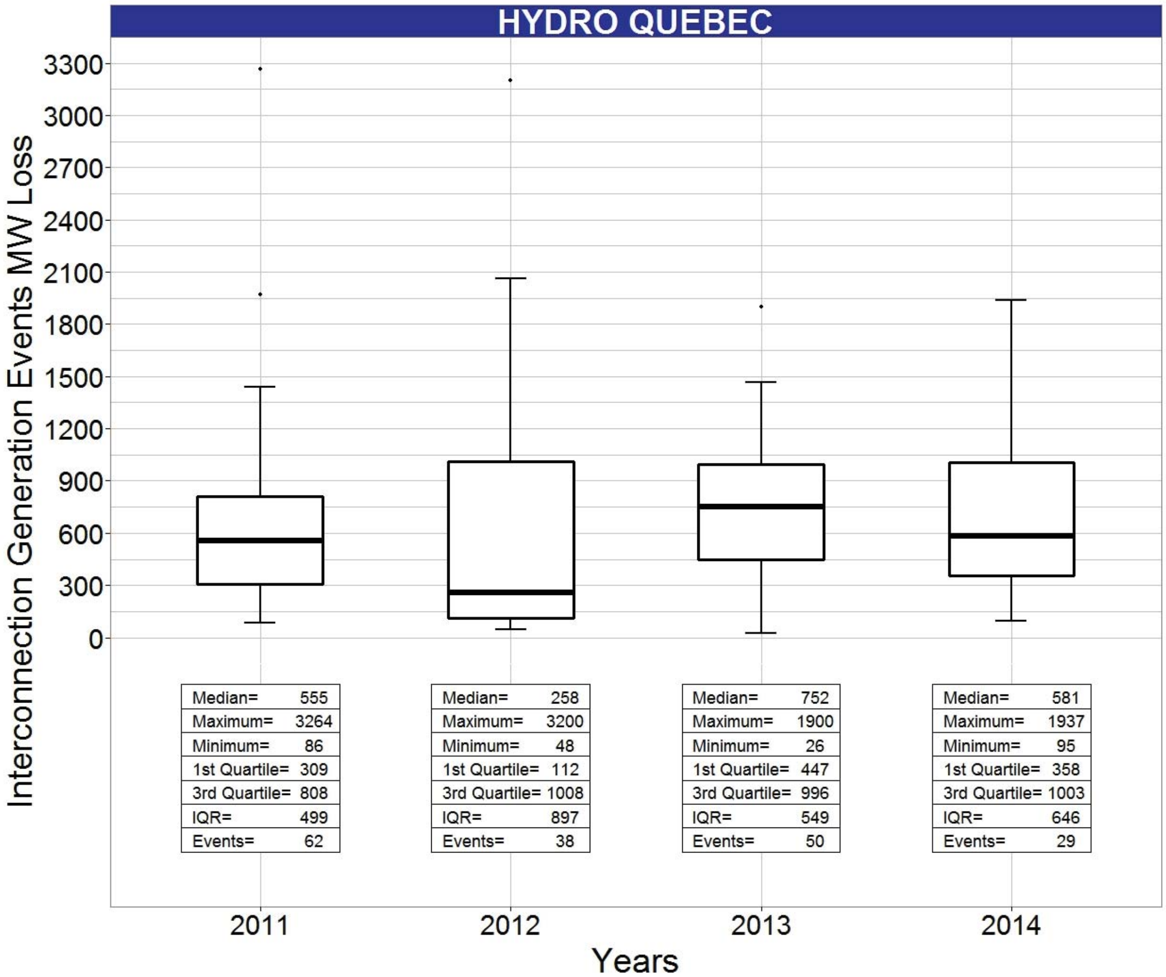
Prepared by: CERTS

Date: October 15, 2013


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Interconnection Generation Events MW Loss
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

BAL-002-2 R1 Example

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*

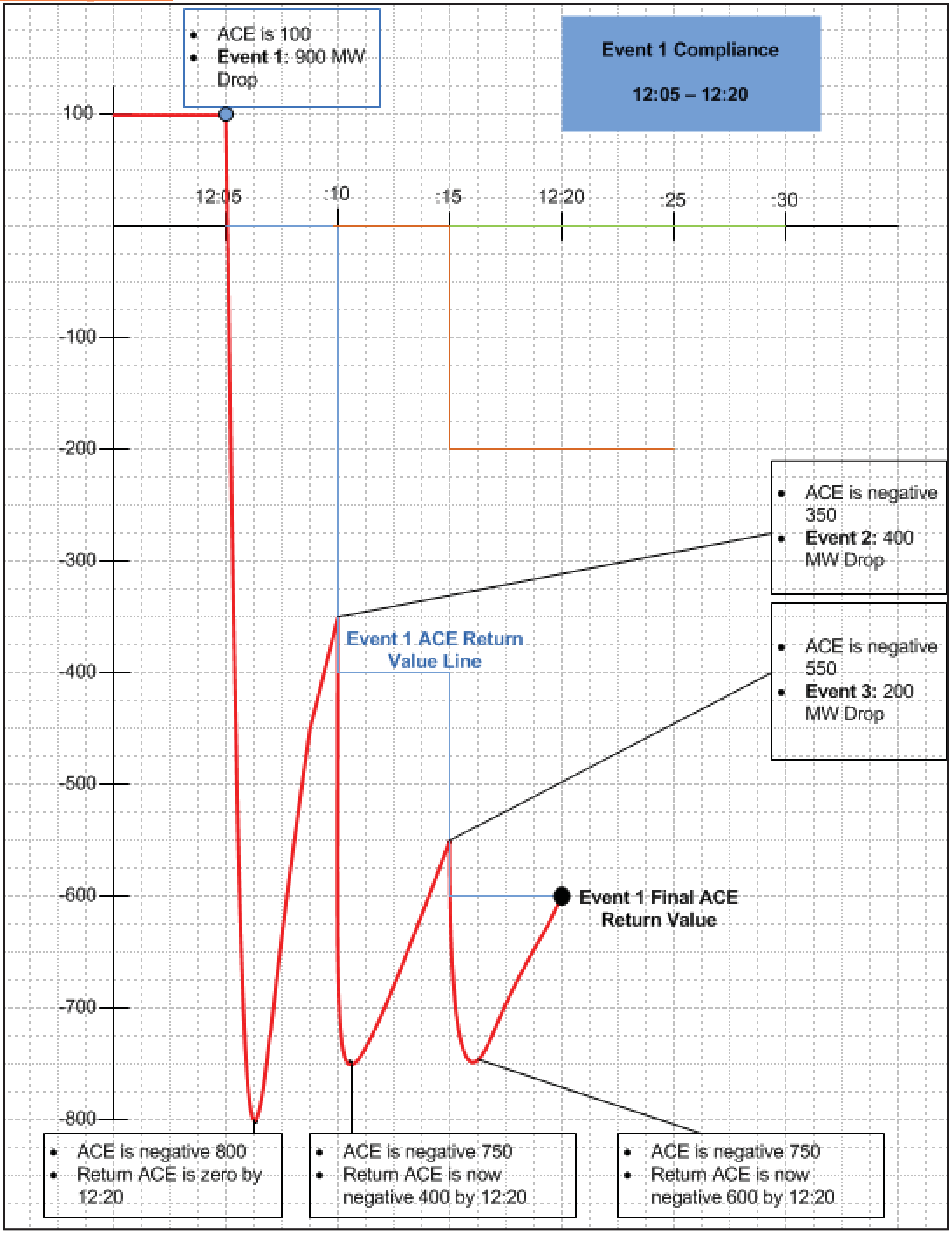
- Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,

Or,

- Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.

To illustrate the above requirement the following scenario of three Balancing Contingency Events, and compliance for each event, is provided. It is assumed in this scenario that the reportable event threshold is 200 MW.

Event 1 Compliance



- Responsible Entity Pre□Reporting Contingency Event ACE Value is 100 MW
- Time of the Balancing Contingency Event □ 12:05
- Size of the Balancing Contingency Event □ 900 MW
- Responsible Entity MSSC □ 2,000 MW

- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery of Event 1 by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.

However, if the Responsible Entity experienced another Contingency Event (Event 2) based upon the following:

- ACE had recovered to negative 350 – prior to Event 2
- Time of the Contingency Event □ 12:10
- Size of the Contingency Event □ 400 MW
- Responsible Entity Reporting ACE Value at 12:10 – negative 750

At the time of Event 2, the Responsible Entity would reduce the value of its required recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2), thus lowering the required recovery value of ACE to negative 400 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Event 2, by returning its Reporting ACE to at least a negative 400 MW by 12:20.

Now if the Responsible Entity experienced an additional Contingency event (Event 3) prior to 12:20 namely:

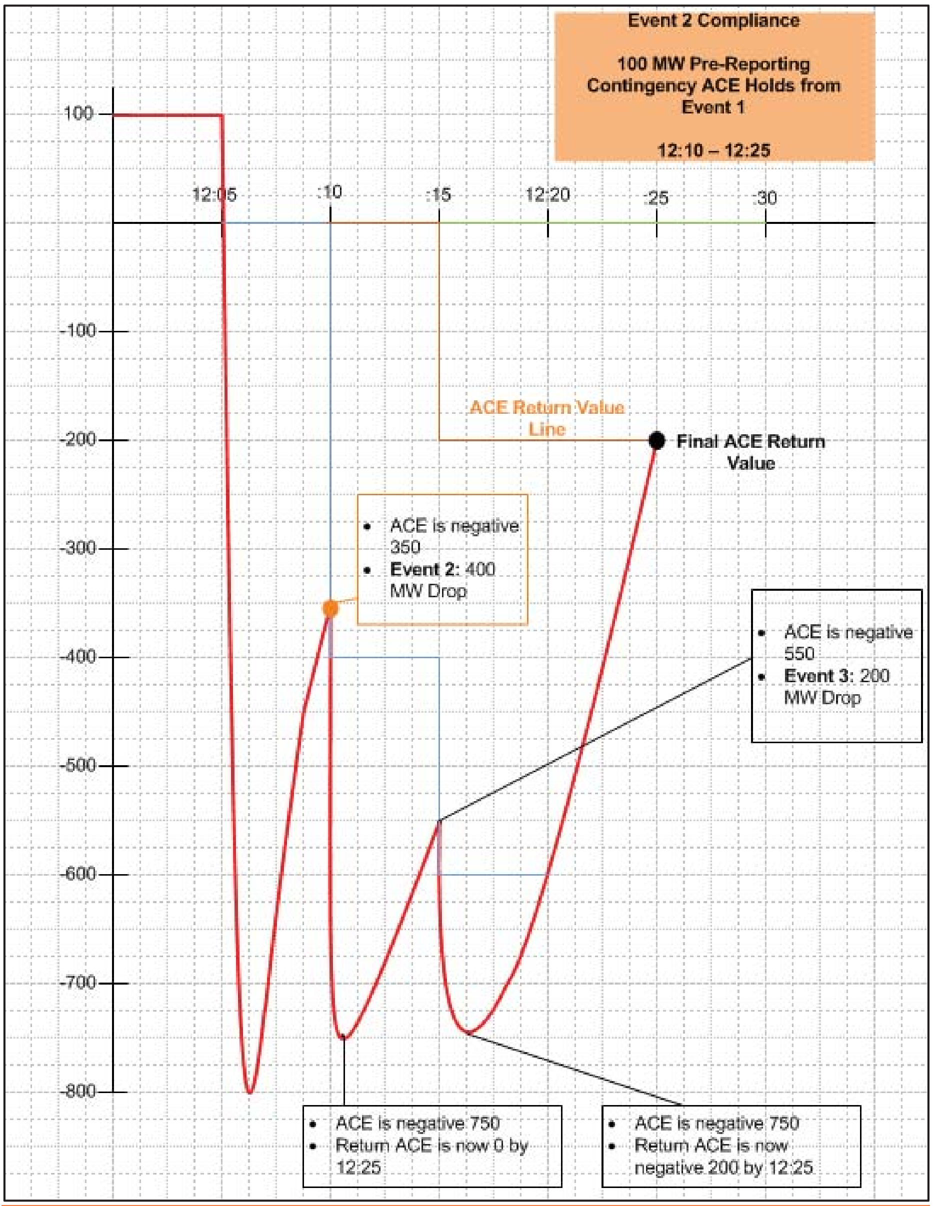
- ACE had recovered to negative 550 MW – prior to Event 3
- Time of the Contingency Event □ 12:15
- Size of the Contingency Event □ 200 MW
- Responsible Entity Reporting ACE Value at 12:15 – negative 750

At the time of Event 3, the Responsible Entity would reduce the value of its required ACE recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2) and the Contingency Event at 12:15 (Event 3), thus lowering the required ACE recovery value to negative 600 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Events 2 and 3 by returning its Reporting ACE to at least a negative 600 MW by 12:20.

The Responsible Entity must show compliance for all events ~~in kind~~ that might occur during the Contingency Event Recovery Period (Event 1). Event 2 and Event 3 from the example above would demonstrate compliance in a similar fashion as was demonstrated for Event 1 above. Each would have its own unique Contingency Event Recovery Period as defined by the start of the respective contingency event (i.e. Event 2's Contingency Event Recovery Period would begin at ~~from~~ 12:10 and end at 12:25; Event 3's Contingency Event Recovery Period would begin at ~~from~~ 12:15 and end at 12:30). ~~However, t~~The ~~Pre-Reporting Contingency~~ required ACE Value (0 MW) of recovery from~~for~~ Events 1; the required ACE Value (-200 MW) of Recovery from Event 2 would be the required Value (0 MW) of Recovery from final Event 3) minus the size of Event 3 (200 MW), while the required ACE Value (-600 MW) of Recovery from Event 1 would be the required Value (0MW) of Recovery from final Event 3 minus the size (600 MW) of the events 2 (400 MW) & 3 (200 MW) subsequent to Event 1.

The following demonstrates the logic used for compliance with Event 2 (from 12:10 – 12:25, including Event 3).

Event 2 Compliance



Responsible Entity's required ACE Value of recovery from Event 2 is 0 MW (the same as it was from the pre-existing initial Contingency Event 1 prior to any adjustment for Event 2)

- Time of the Balancing Contingency Event 12:10
- Size of the Balancing Contingency Event 400 MW
- Responsible Entity MSSC 2,000 MW

- Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery from Event 2 by returning its Reporting ACE to Event 1's prior, unadjusted Pre-Reporting Contingency Event ACE value of 0 MW within the Contingency Event Recovery Period, or by 12:25.

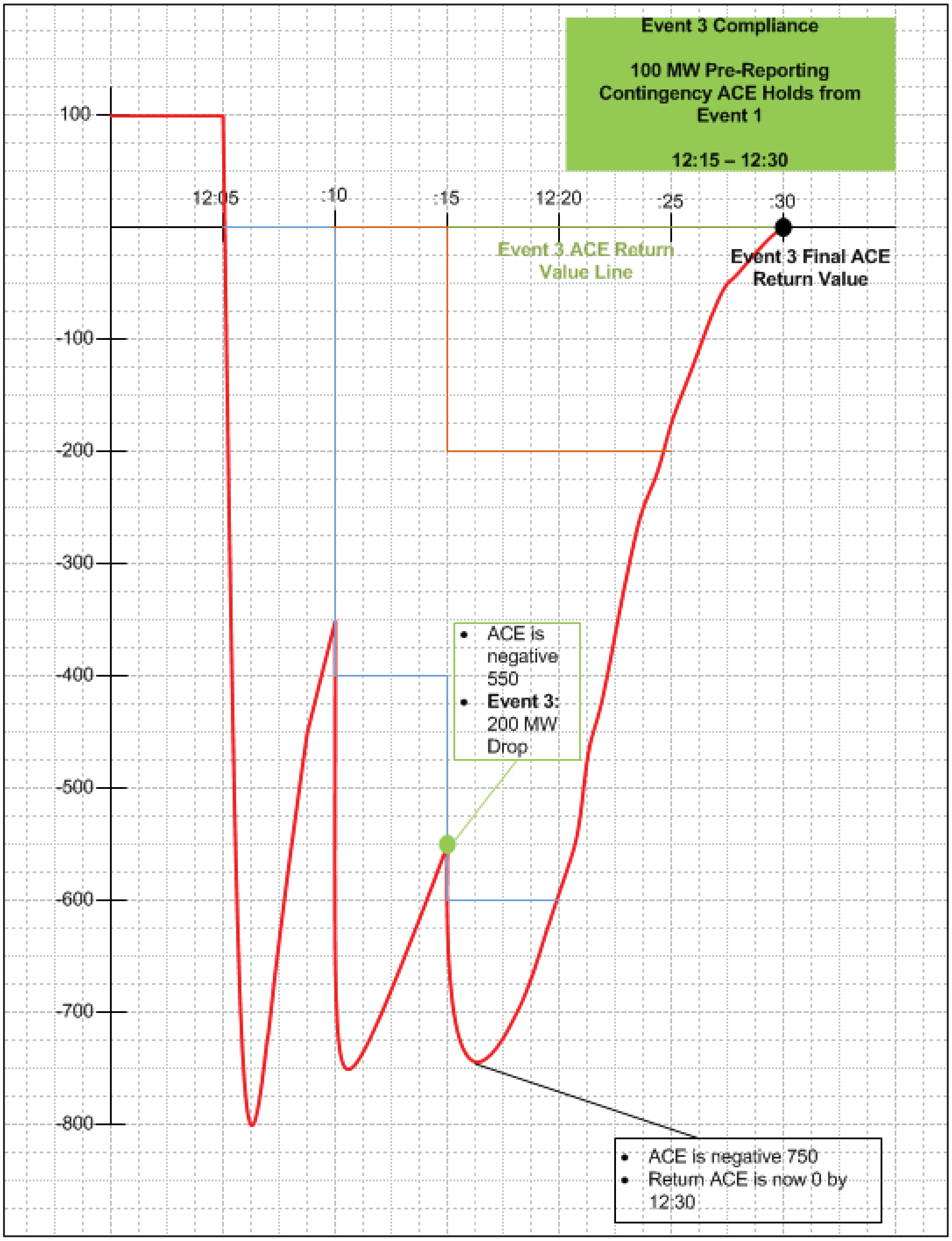
However, the Responsible Entity experienced another Contingency Event (Event 3) based upon the following:

- ACE had recovered to negative 550 – prior to Event 3
- Time of the Contingency Event 12:15
- Size of the Contingency Event 200 MW
- Responsible Entity Reporting ACE post Contingency Event – negative 750

At the time of Event 3, the Responsible Entity would reduce the value of its required recovery from the Balancing Contingency Event 2 by the size of Contingency Event 3 at 12:15, thus lowering the required ACE recovery from Event 2 to negative 200 MW. The Responsible Entity would demonstrate recovery from both Balancing Contingency Event 1 and Balancing Contingency Event 2, taking in to account Event 3, by returning its Reporting ACE to at least a negative 200 MW by 12:30.

The following demonstrates the logic used for compliance following Event 3 (from 12:15 – 12:30).

Event 3 Compliance



The Responsible Entity's required ACE Value of recovery from final Event 3 is 0 MW (the same as it was from the initial Balancing Contingency Event 1 prior to any subsequent events)

- Time of the Balancing Contingency Event 12: 15
- Size of the Balancing Contingency Event 200 MW
- Responsible Entity MSSC 2,000 MW

  Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW

With no additional Contingency Events, the Responsible Entity must demonstrate recovery of final Event 3 by returning its Reporting ACE to the 0 MW ACE value of 0 MW of recovery from the initial Event 1 within the Contingency Event Recovery Period, or by 12:30.

The above examples illustrate the minimum response for compliance. Actual events and recoveries will differ because of matters such as, but not limited to, Contingency Reserve being deployed differently.

~~In order to illustrate the above requirement the following is provided:~~

~~Responsible Entity Pre-Reporting Contingency Event ACE Value is 100 MW~~

~~Time of the Balancing Contingency Event - 12:05~~

~~Size of the Balancing Contingency Event - 900 MW~~

~~Responsible Entity MSSC - 2,000 MW~~

~~Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW~~

~~With no additional Contingency Events, the Responsible Entity must demonstrate recovery by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.~~

~~However, if the Responsible Entity experienced another Contingency Event based upon the following:~~

~~Time of the Contingency Event - 12:10~~

~~Size of the Contingency Event - 400 MW~~

~~Responsible Entity Reporting ACE Value at 12:10 – negative 750~~

~~The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:10, thus resulting in the required ACE being reduce by 400 MW to negative 400 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 400 MW by 12:20.~~

~~Now if the Responsible Entity experienced an additional Contingency event prior to 12:20 for example:~~

~~Time of the Contingency Event - 12:15~~

~~Size of the Contingency Event - 200 MW~~

~~Responsible Entity Reporting ACE Value at 12:15 – negative 750~~

~~The Responsible Entity would reduce its required recovery value for the Balancing Contingency Event required recovery by the size of the Contingency Event at 12:15, thus resulting in the required ACE recovery being reduced by another 200 MWof to negative 600 MW. The Responsible Entity would demonstrate recovery from the Balancing Contingency Event by returning its Reporting ACE to a negative 200 MW by 12:20.~~

~~This would continue on for any additional Contingency Events that might occur during the Contingency Event Recovery Period. Note that the adjustments to the Reportable ACE value required for recovery are made only after the subsequent Balancing Contingency Event fully occurs.~~

Attachment 3

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

Project 2010-14.1 Mapping Document
Transition of BAL-002-0 to BAL-002-2

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R1	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R2	This requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R3	Requirement R1 and R2	This requirement was broken apart. The requirement was defining two separate actions; 1) to require activation of Contingency Reserves, and 2) to require having Contingency Reserves equal to its MSSC.
BAL-002-0 R4	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" and "Contingency Reserve Restoration Period" definitions.	A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R5	This Requirement has been moved into BAL-002-2 Requirement R1 and "Reserve Sharing Group Reporting ACE" definition.	A portion of this requirement was defining how a RSG calculates its ACE. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.
BAL-002-0 R6	This Requirement has been moved into the BAL-002-2 Requirement R1 and "Contingency Event Restoration Period" definition.	A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2

Formal Comment Period Open through March 16, 2015

Now Available

A 45-day formal comment period for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern on Monday, March 16, 2015.**

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 6 – March 16, 2015**.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Darrel Richardson, Standards Developer, or at 609-613-1848.

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Individual or group. (24 Responses)
Name (9 Responses)
Organization (9 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (4 Responses)
Comments (24 Responses)
Question 1 (20 Responses)

Group
MRO-NERC Standards Review Forum
Joe Depoorter
Madison Gas and Electric Company
We commend the drafting team on the improvements made since the last posting. Below are our concerns and recommendations for improvement. The NSRF is concerned that the lowering of the threshold to 900 MW for the Reportable Balancing Contingency Event in the Eastern Interconnection, coupled with the proposed change from quarterly average performance to individual event performance will increase customer costs and significantly increase compliance exposure for no difference in reliability risk. Because the interconnection is over-biased (ACE overstates resource loss) and operators operate conservatively, they will likely deploy contingency reserves for any loss over 800 MW. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the Eastern Interconnection. Don't Change from Present Quarterly Reporting: We have fundamental concerns with changing the current quarterly reporting to exception reporting. We can find no directive for this change which increases compliance exposure and will have unintended consequences in how Reserve Sharing Groups (RSG) will operate. A failure of a contingency resource to start or start a minute late can cause performance that has a very low score for that single event, even though recovery is only a minute late or two late. There are RSGs that mitigate this compliance risk by deploying reserves for much smaller events, which helps reliability by quickly recovering from smaller events and replenishing these reserves as well as giving operators repeated practice in reserve deployment. Since each and every event is individually sanctionable, these RSGs will quickly change their rules to raise their reportable threshold to the interconnection minimum. Exception reporting will also eliminate a data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx, which is another step backward. We believe there should be a single quarterly report for R1 and R2. The R1 portion would be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of hours the BA

had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. The VSLs should be based on the number of hours that reserves were < MSSC and not excluded: • Low: 2 or fewer hours (represents 0.09% of the hours in the quarter) • Medium: 3-5 hours • High: 6-9 hours • Severe: 10 or more hours (10 hours represents 0.5% of the hours in a month) NERC is trying to move away from zero defect standards. This standard should be structured to support that concept. The reporting approach need not hard coded in requirements, but could be compliance section of the standard. We also had comments on a few specific items in R1. Our suggested wording changes are in [ ]. *** 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated [or depleted]. *** Contingencies can happen that take away reserves without the reserves being activated. And if these contingencies aren't "sudden", then it appears there is no acknowledgment of the reserve loss under the standard. *** (ii) after multiple Balancing Contingency Events for which the combined [capacity] magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. *** Contingencies of partially loaded generators remove not only MW from the BA, but the reserves they had as headroom. It is possible to have multiple contingencies where the MW loss is < MSSC, but reserves that were lost completely deplete the BA of its contingency reserves. There should be clarification that the magnitude loss is based on capacity, not MW loss.
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
There is a possible inconsistency in the terms Balancing Contingency Event, and Reportable Balancing Contingency Event. Balancing Contingency Event is defined as "Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute..." Reportable Balancing Contingency Event is defined as "…(ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE…" By its definition, the Balancing Contingency Event, in the extreme, is an unlimited number of single events, as long as they are separated by less than one minute. Is it intended for a Reportable Balancing Contingency Event to only encompass what happens in the first minute as it is worded? In the NERC Glossary, Reportable Disturbance is defined as "Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance." The definition of Reportable Balancing Contingency Event should be revised to incorporate this definition, and should be made to read"…(i) Reportable Disturbance, or…". With this revision, when BAL-002-1 is retired the definition of Reportable Disturbance can be retired as well. Regarding the Rationale for

Requirement R1, should Reportable Area Control Error be Reporting ACE? Reporting ACE is in the NERC Glossary, Reportable Area Control Error is not. In the second paragraph of the Rationale for Requirement R1 that reads"…as described in R1.3 below…" should be revised to read "as described in Part 1.3…". Measure M1 should be revised to read "…that demonstrates compliance with Parts 1.2 and 1.3.". In Requirement R2, and Measure M2 "Firm" should not be capitalized. "Firm Load" is not in the NERC Glossary. It should be revised to read firm Load. Additional comments: 1) The proposed standard continues with several "compliance traps" which will hamper operators' effective use of Contingency Reserves to mitigate reliability problems, and then could cause compliance exposure due to auditor interpretation. For example, R1 would require a BA to deploy at least some of its reserves in order to declare an EEA exemption even if there may not be an immediate need to do so. 2) There are contradictory portions of the standard which would leave operators confused and again lead to compliance exposure. a. For example, Part 1.3 (ii) does not include an exemption for deploying Contingency Reserve for a Contingency that is not a NERC defined Balancing Contingency Event. R2 does have an exemption for this and other scenarios. The term "sudden" being included in the definition of a Balancing Contingency Event is the source of the problem. See the second scenario of Attachment A (sent by E-mail to Darrel Richardson). b. R1 does not treat subsequent Contingencies in a consistent manner, again related to the term "sudden" being included in the definition of a Balancing Contingency Event. See the first scenario in Attachment A (sent by E-mail to Darrel Richardson). 3) There are several problems with the definitions including definitions of Most Severe Single Contingency (MSSC), Contingency Event Recovery Period (CERP), and Balancing Contingency Event (BCE). a. MSSC does not include concurrently dropped load which may cause a Balancing Authority to carry extra Contingency Reserve beyond its actual MSSC. b. BCE is unclear with regard to both generation and transmission events. (Also consider if A. Item b within the BCE definition instead referred to an unplanned change in ACE as opposed to an unexpected change in ACE.) 4) Regarding R2: a. R2 is far more complex than necessary, is unclear, and contains potential for gaming. b. Much less complicated language is proposed here, based on the original NERC Policy 1. Suggest the revision of R2 to read: R2. The Responsible Entity, if deficient in Contingency Reserves, has 90 minutes to restore. If the Responsible Entity experiences a Reportable Balancing Contingency Event during this time an additional 15 minutes are allotted." An alternative suggested rewording of R2: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. This, together with the recovery provision in R1 (results-based requirement) and the provision in Requirement R6 and Attachment 1 of EOP-011-1 (which defines EEA levels) would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 as shown preceding. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. c. The language in Part 2.2 regarding Operating Instruction appears to allow operating personnel to create exemptions from R2 at will. d. Requirement R2 continues to not include a number of “grace hours” per quarter, as requested in some industry comments. It may have a net effect of increasing the amount of available contingency reserve to some BAs which may marginally increase reliability. However, this needs to be balanced against increased operating costs due to carrying more reserve. e. Requirement R2 may produce a perverse incentive. A BA may let its ACE remain negative to keep the reserve monitor numbers above MSSC. Also, without a number of "grace hours" per quarter, there may be a susceptibility to loads running unexpectedly high near the end of a Clock Hour, causing a miniscule shortfall that results in an occasional "nuisance" compliance violation. f. R2 also causes BAs to carry much higher Contingency Reserves than necessary during the latter portions of the hour in order to “make the numbers come out right” if they are below MSSC in the beginning of the hour. g. Requirement R2 creates an artificial increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, thereby increasing costs to ratepayers for no increase in reliability. h. R2 will encourage operators to not deploy reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability. i. Entities that have to shed firm customer load (because load cannot be shed fast enough) to maintain reserves to meet compliance with this requirement is not an action that should be taken for reliability. j. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met requirement R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. k. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted item may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the excedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL). 5) The last sentence of metric M2 which splits a Clock Hour into sub-periods is difficult to follow and seems to add unnecessary complexity in determining compliance. 6) When the exemption in Part 2.6 becomes relevant, it most likely will occur within the middle of a Clock Hour. It is not clear if "instantaneous values showing reserves" refers to the sum of Contingency Reserve available plus Firm Load that can be shed. 7) Part 1.3 and R2 should be cognizant of unexpected loss of reserve without it being accompanied by a loss of power being delivered. In the last posting, we expressed a concern with the term “sudden loss” (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The

word “sudden” is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. To summarize, the January 2015 version of BAL-002-2 could be improved by providing better clarity within the definitions and making simplifications that yield a more "operator-friendly" standard. There is a concern that the complexity and nuances of the proposed standard in some circumstances could be a distraction to the operator when more important reliability tasks need to be performed.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
PJM
Individual
Leonard Kula
Independent Electricity System Operator
1. In the last posting, we expressed a concern with the term “sudden loss” (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. 2. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed

in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL)
Group
Seattle City Light
Paul Haase
Seattle City Light
Seattle City Light supports Balancing Authorities having the flexibility to use Contingency Reserve to respond to other reliability events and votes affirmative for this ballot. Seattle would support the draft more, however, if the term "clock hour average" was replaced with "instantaneous value" throughout the Standard. Using Hourly averages places entities in the position where they may be incentivized to have less Contingency Reserve than their current Most Single Severe Contingency for large percentages of key operating hours. From a financial perspective, there is nothing in this revision stopping a Balancing Authority from having less Contingency Reserves than their Most Single Severe Contingency during the last 20 to 30 minutes of every steep load pick up hour every day.
Group
Florida Municipal Power Agency
Carol Chinn
Florida Municipal Power Agency
FMPA supports the comments of Duke Energy
Individual
Kathleen Goodman
ISO New England

Agree
NPCC RSC and IRC SRC
Group
Arizona Public Service Company
Kristie Cocco
Arizona Public Service Company
APS would like the Drafting Team to clarify the following question about the draft language. R1.2 states “A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.” Since only a Balancing Authority can be declared to be in an RC-approved EEA, how would that impact the RSG that the Balancing Authority is a member of since that would be how they would be reporting their compliance with R1? Differently stated, does the RSG that the BA is a member of receive a waiver from R1 if the member BA is in an RC-approved EEA?
Group
Con Edison, Inc.
Kelly Dash
Consolidated Edison Company of New York
Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material section: there is no substantial information contained in this section of the document. Is it the intent of the drafting team to fill-in these sections at a later date? If so, when would it be completed? If not, why not?
Individual
Terry Bilke
MISO
We commend the drafting team on the effort committed to this project and appreciate the improvements. We also appreciate the various objectives the team is trying to meet, but believe it is time to step back and ensure we are moving in a direction where NERC is trying to go with clearer, results-based standards. We understand that the team is trying to meet their interpretation of Order No. 693 directives. We respectfully submit that much of what the FERC directed may be moot as the directives related to primary, secondary, and tertiary control, have been met by other standards projects. This is particularly true considering the equally effective R2 (Balancing Authority ACE Limit, BAAL) in BAL-001-2 and a performance based Frequency Response Standard. The current BAL-002 is well understood by system operators and performance as posted on the NERC “Adequate Level of Reliability (ALR) Metrics” website has been stellar. The draft out for comment is not easily understood, adds complexity, and will likely increase customer cost for no discernable reliability value. If the

standard effort reaches an impasse, it may be time to hold a technical conference to get resolution on a few key items: 1] What should be the obligation of the Balancing Authority for events > MSSC? [We suggest that such events are reported to demonstrate best efforts were made, but compliance is not assessed. The BA is still accountable for BAAL. Finally there are backstop standards as load shedding is mandated in the EOP and IRO standards for harmful frequency conditions and IROL exceedances] 2] What constitutes a continent-wide contingency reserve policy? [We believe the policy could be met by developing simple definitions for the various categories of operating reserves as any can be used to meet DCS or the other Balancing Standards in real time. The policy should state that the BA performs an analysis to develop warning and alarm points for their operators for the reserves needed to meet BAL-001, BAL-002, and BAL-003. Having BAs provide this data to in real time to their Reliability Coordinators would add reliability value to the EEA and other EOP processes. Finally, a guidelines document on reserves approved by the NERC Operating Committee could be part of this policy] 3] Since there are now performance based BAAL and FRS in place, could we not actually simplify the current DCS? [Retain a cleaner version of the current R1, and a simpler R2 that requires presenting reserve values to BA and RC with appropriate alarm points] 4] The extent the remaining 693 directives have been met by other standards projects. [We believe BAAL addresses the Commission's concerns for detecting and responding to significant high or low frequency events, addresses the concern about performance to individual events, and is a performance-based double-confirmation of secondary and tertiary reserves] 5]For those requirements that are ultimately proposed, is there a way to keep them simple and easy to understand as opposed to being overly precise [For example, if there are exclusions in a requirement, rather than trying to calculate reserve recovery to the minute, exclude the hour when the situation occurs and the following hour(s), the number of hours determined by the extent contingency reserves were depleted)? We agree with comments submitted by the IRC-SRC and MRO-NSRF as applied to the current draft. The question is whether to continue to adjust the current draft or make sure we are creating a solution that is relatively simple to apply and provides reliability value. If we continue down the current path for the standard, we have two primary concerns. Our first concern is that the lowering of the threshold to 900 MW in the East, coupled with the proposed change from quarterly average performance to individual event performance, will increase customer costs for no discernable reduction in reliability risk. Both DCS performance (ALR statistics) and frequency performance (NERC Resources Subcommittee minutes) show frequency performance is more than adequate. As noted by Chairwoman LaFleur at NERC Board meetings, we should consider the reliability benefits of a standard vs. its costs. Costs will increase with the lower threshold for our customers. Because the interconnection is over-biased (ACE overstates resource loss) and dispatchers operate conservatively, our operators will likely deploy set-aside contingency reserves for any loss over 750 MW rather than wait to double-check the event size. This will likely add scores of contingency reserve deployment cases each year for situations that could likely be met by other on-line reserves. Finally, it should be noted that the frequency change from a 900 MW loss in the East is barely beyond the change from a Time Error Correction. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the East. We also recommend that NERC retains the quarterly reporting. Individual cases of non-

compliance can be tallied in the form to achieve the FERC directive, but we believe it is important that Enforcement assesses compliance base on the aggregate performance of the BA or RSG, not just spot observations. Our second major concern with the current posting for comment is that R2 goes beyond the original intent of the DCS. The reason there are no measures for this requirement in BAL-002-0 is that it was never intended to be a commodity standard. The predecessor to DCS was Policy 1, which had guidelines on operating reserves. The first DCS was one of NERC's first performance-based standards and existed prior to the ERO. The intent was to retain the concept of the guide to plan to have a certain amount of reserves. The measures of success were to meet CPS and DCS. DCS' intent was to respond quickly to all large events, with performance evaluated on events 80%-100% of MSSC. The intent of the 90 minute reserve replenishment was to get ready for future events (meaning you'd be held for compliance to the standard for events 90 minutes thereafter). Another reason for our concern is that this commodity requirement is being proposed without any data to support what actually is carried hour to hour across the Interconnections and the extent operators draw on these reserves to keep their system balanced. If R2 is retained as proposed, we believe that it should be a "positioning" requirement, not a zero-defect requirement. As proposed, either customer costs will increase or reliability will be negatively impacted. The only way to have more than 100% reserves all the time in normal operations is to carry well more than 100% reserves as a basis of operations or choose not to deploy reserves for non-reportable events and draw on frequency bias to keep reserves available. While the proposal provides some exclusions, the requirement should start on the basis that there will always be some variability and unforeseen non-consequential events that will require reserve deployment. If retained, we suggest R2 should require contingency reserves > 100% MSSC for 99% of all applicable hours. It should be noted that just because a BA has less than MSSC in one hour in four days, does not mean that it had zero reserves in that hour. Additionally, in a multi-BA Interconnection, the odds that the Interconnection would be deficient in Reserves with a 99% BA standard are astronomical. In a single-BA Interconnection there are backstops in the EOP and IRO standards. BAL standards are for normal operations. Other standards protect against events > N-1. Finally, we believe there should be a single quarterly report for R1 and R2. The R1 portion should be simplified to be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of non-excluded hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
BAL-002-2 Shouldn't 'transmission' as used in the definition of Balancing Contingency Event in A.a.iii. and B. be capitalized? Several standards recently have foregone the Effective Date section in the standard and instead refer to the Implementation Plan for the specific implementation dates. Should that be considered here? Use lower case 'requirement' in the

3rd line of the Background material. Contingency Reserve should probably be capitalized in the 1st, 2nd and 4th paragraphs of the Rationale Box for Requirement R2. Delete the 's' on 'suites' in the 11th line of the 2nd paragraph of the Rationale Box for Requirement R2. Shouldn't 'load' be capitalized in the 4th paragraph of the Rationale Box for Requirement R2? Background Document Consistency is needed throughout the document in the capitalization of terms such as 'Transmission', 'Contingency Reserve', 'requirements', 'Transmission Line', 'Responsible Entity', 'Load', 'Real-time', 'energy deficient entities', 'event', 'field trials' and 'firm load'. In some situations, the SDT uses 'SDT' and in others it simply uses 'drafting team'. Be consistent throughout. Replace 'Balancing Authority or Reserve Sharing Group' with 'Balancing Authority (BA) or Reserve Sharing Group (RSG)' in the 9th line of the 3rd paragraph on Page 3. Subsequent uses of these terms should then be BA or RSG, respectively. Insert '(MSSC)' immediately following 'Most Severe Single Contingency' in the 2nd line of the 2nd paragraph on Page 4. Replace 'Standard' in the 6th line of the same paragraph with 'standards'. Replace 'the real-time operations' with 'Real-time operations' in the 1st line of the 1st paragraph under Balancing Contingency Event on Page 5. Replace 'requirement' with 'directive' in the last line of the 2nd paragraph under Balancing Contingency Event on Page 5. Replace the 3rd bullet at the top of Page 7 with the following: 'resolving the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) that requires the use of Contingency Reserves; and'. Replace 'requirements' with 'directives' in the 4th line of the 4th paragraph on Page 9. Replace 'suites' with 'suite' in the 1st line in the 1st paragraph at the top of Page 10. The SDT is to be commended for the improved clarity in the examples in Attachment 2. The reference sited in the last line of the 2nd paragraph on Page 34 (Footnote 5) is not attached. It's referenced in Footnote 5. There is no Footnote 3 as referenced in the 3rd line of the paragraph under Control Performance Standards (CPS1) on Page 34. CR Form 1 In cell A15 of the Read Me tab, use lower case 'it'. In cell A1 of the Exemption tab, replace 'Exemp' with 'Exempt'. In cells A10 and A16 of the Description tab, © appears instead of the intended (c). Thanks Microsoft. In cell A11 of the Entry Instructions tab, insert 'with' between 'associated' and 'subsequent'. In cell A4 of the Calculator tab, insert 'the' between 'Enter' and 'name'.
Group
Duke Energy
Colby Bellville
Duke Energy
General Comments: Duke Energy would like to take the opportunity to offer comment on the overall project concerning BAL-002-2 in conjunction with the recent FERC NOPR issued on November 20, 2014. FERC issued a NOPR proposing the approval of the BAL-001-2 standard (Real Power Balancing Control Performance). FERC commented in its NOPR that further revisions to the BAL-002 standard should take into consideration, the impact the revisions may have on the Balancing Authority ACE Limit (BAAL) in BAL-001-2. Duke Energy agrees with the Commission that the potential impact that compliance with BAL-002 may have on BAAL should be taken into consideration during further modifications to BAL-002, and suggests that

this project be tabled until the final order issuing the approval of BAL-001-2 has been handed down by FERC. Balancing Contingency Event: Duke Energy would like to re-state its concerns with the proposed definition of Balancing Contingency Event. Originally, we stated that we sought clarification on item B of the Balancing Contingency Event (BCE) definition. A BCE should be predicated on a deviation in Area Control Error (ACE) . As written, we are unclear why item B is even part of the definition because we believe Item B is redundant with item A.a.ii. We fail to see the additional clarity that Item B provides, and could see where questions could arise regarding the differences between the two items in the future. Background: In the revised background section of the proposed BAL-002-2, the section alludes to frequency management, however, we fail to see any requirement in this standard pertaining to frequency management. R1: We would like to offer our previous comment on this requirement for the drafting team's consideration. Duke Energy suggests the following revision to R1.2: "1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load." We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R1 during those instances where Contingency Reserves are utilized to serve load. Duke Energy requests further clarification on what is meant by the reference to activate Contingency Reserves under an Energy Emergency Alert (EEA). R1 Rationale: If the SDT's intent is to eliminate any potential overlap with other standards, this will not be the case once the BAAL is in place. If BAL-001-2 is approved, there will be another standard driving a BA to take corrective action when frequency is hurting. Again, we caution the SDT that moving forward with the BAL-002-2 project without taking into consideration the BAAL, could result in conflicting standards. In addition, we believe that there are situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. For example, as the Disturbance Control Standard ("DCS") under BAL-002 is measured event-by-event, a Balancing Authority is required to return its ACE to zero with 15-minutes after a Reportable Disturbance (or back to its pre-Disturbance ACE value if that value was negative). Such a response in the future may be a problem if the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2. If a generation resource was lost in the middle of the night during a period of minimum load concerns, numerous available generation resources, and high Interconnection frequency, BAAL would drive the Balancing Authority to take appropriate action over a reasonable timeframe. DCS would not consider any of these factors but would require the Balancing Authority to strictly comply. This strict compliance with BAL-002 could have a detrimental impact on Interconnection frequency. R2: Duke Energy requests further clarification from the drafting team on whether its intent was for the standard to be worded in such a manner to allow for the waiving of immediate restoration of reserves. Is it the SDT's intent to afford an entity the opportunity to wait for a period of 90 minutes, before requiring the restoration of reserves to take place? Also, Duke Energy suggests a re-ordering of the sub-requirements for R2. Sub-requirements 2.4 and 2.5 should be first and second on the list of sub-requirements based on the reasoning that they would be the most common instances. Regarding sub-requirement 2.6, we feel that clarifications are needed. As written

currently, it is unclear whether an entity has to actually shed load for 2.6 to apply, or if you have to just be prepared to do so. There are concerns that requiring compliance documentation to demonstrate that you were prepared to take some action, even though said action never took place, could be considered onerous. Lastly, upon our review, it could be argued that some of the sub-requirements appear to mirror closely responsibilities that are already present in EOP-002. We suggest that the SDT consider delaying implementation of BAL-002-2 so that it becomes effective after EOP-011-1.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Energy, LLC
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The PPL NERC Registered Affiliates support the comments provided by PJM. In addition, we submit the following comments: It is not clear how the compliance exemptions in R1.2 and R2.6 for a Responsible Entity experiencing an EEA would apply to a RSG. Since an RSG cannot request the RC to declare an EEA , it appears the RSG would be required to maintain MSSC level reserves regardless of the EEA status of its member BAs. It also appears the RSG could be found non-compliant with both R1.2 and R2.6 simultaneousl. We suggest that while a member of a RSG is in an EEA, its MSSC and Contingency Reserve Requirement (the member BA’s reserve obligation to the RSG) are removed from the RSG. The reconfigured RSG would continue to maintain the RSG based on the new MSSC and the revised assignment of CRR among the non-EEA members. The RSG would remain in this configuration for the duration of the member BA’s EEA. Assigning a Medium VRF to both R1 and R2 is not appropriate – the reliability impact of not having the required amount of reserves does not seem comparable to the reliability impact of not recovering ACE after a reportable BCE. The VRF for R2 should be lower than R1. If R2 cannot be revised as suggested by PJM, an alternative to the average Clock Hour measurement period should be provided. If reserves dip below the MSSC late in a Clock Hour, it is doubtful if a RE could act in time to resolve the shortfall. Also, what is the reliability benefit of an RE acting to increase its reserves if the shortfall occurs earlier in the hour? It doesn’t seem the average Clock Hour measurement period provides an RE much flexibility in complying with R2 nor does it improve BES reliability. A rolling hourly average or multi-Clock Hour average would be an improvement. BAL-002-2 directly applies only to BAs and Reserve Sharing Groups, but it states in the definition of Contingency Reserve that the capacity mandated, “may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation.” That is, BAs can fulfill their BAL-002-2 obligations only by imposing demands on these other parties, and we would like to know up-front what they will be. This concern is heightened by the addition (effective 4/1/2015) of the

expression, “and discourage response withdrawal through secondary control systems,” to the NERC Glossary definition of Frequency Bias Setting. This change echoes the statement, “appropriate outer-loop controls (distributed controls) settings to avoid primary frequency response withdrawal,” in the NERC Resource Subcommittee’s 2013 Eastern Interconnection Frequency Initiative Whitepaper,” and “Related outer-loop controls within the DCS, as well as applicable generating unit or plant controls, should be set to avoid early withdrawal of primary frequency response,” in NERC’s 2/5/2015 Industry Advisory, Generator Governor Frequency Response.” Implementation of appropriate governor time delays and droop settings constitutes a well-defined and technologically justified form of GO involvement in frequency response improvement, but the term “response withdrawal” is vague and could cause BAL-002-2 to be misconstrued as authorizing BAs to demand new, frequency response-enhancing services from GOs as a regulatory requirement rather than obtaining them through market mechanisms.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word “shall” instead of “will” to make mandatory the use of the noted CR Form 1. The term “shall” indicates a duty on the subject and is used throughout the NERC Standards in this manner; in this case the responsible entity has a duty to use CR Form 1, so “shall” is the more appropriate term. ReliabilityFirst recommends attaching it to the standards along with the following change for consideration: “The Responsible Entity shall document all Reportable Balancing Contingency Events using Attachment 1 - CR Form 1.” 2. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as a reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst recommends completely removing the second paragraph within Measure M2 from the standard.
Group
Associated Electric Cooperative, Inc.
Phillip Hart
AECI
AECI respectfully requests that the SDT further consider modifying the Contingency Event Recovery Period to 30 minutes, or provide empirical evidence that demonstrates a risk to reliability exists when a Responsible Entity exceeds 15 minutes before recovering their ACE to the pre-disturbance level. Absent a risk to reliability when exceeding 15 minutes, the use of

30 minutes for the Contingency Event Recovery Period would more closely align with other reliability standards requirements that relate to operation of the BES during events, specifically the amount of time allowed for an entity to exceed an IROL.
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 Hunter
Southern Company Operations Compliance
In regards to R2.6: In an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Southern agrees that a BA should not be required to maintain Contingency Reserves during an applicable Energy Emergency Alert level (for Southern that would be an EEA3). Our concern is with how the following sentence is phrased “For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.” We recommend a different approach so that it reads, “For this exemption to apply, the deficient BA must be able to execute interruption of Firm Load to restore ACE within the Contingency Event Recovery Period timeframe”. The rationale behind this change is if a deficient BA can recover ACE within Contingency Event Recovery Period via load shed this should be an acceptable practice but they must have the ability to execute completely this action within the Contingency Event Recovery Period timeframe (e.g. 15 minutes). Southern agrees with the drafting team that in an EEA3 a BA should be able to consider load shed as a viable practice to maintain ACE and not be required to re-establish Contingency Reserves by shedding load pre-contingency. The current way the Measure is worded supports this purposed change.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Agree
Group
Peak Reliability
Jared Shakespeare
Peak Reliability

General: BAL standards should be developed as a group and not individually. R1.2: “A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.” EOP-002-3.1 speaks to the RC initiating/declaring but not approving an Energy Emergency Alert. It can be argued that parameters are in place to make a decision on approval but nevertheless there is no mention of approvals nor defined approval processes within the standard. Suggestion is to revise from “approved” to “initiated/declared” to remain consistent with EOP-002-3.1. R2: Peak is concerned that using an average clock hour might allow entities to take advantage. For example, if an entity is deficient the first 30 minutes but sufficient the second 30 minutes, the average clock hour would be met but the first 30 minutes would be in an unreliable state.
Individual
Catherine Wesley
PJM Interconnection
1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution. Comments: PJM appreciates and recognizes the work of the SDT as reflected in the present posting of the proposed BAL-002-2. PJM strongly urges the SDT to incorporate the following changes. R1 Suggested changes: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] • Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Eevent, or, • Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Eventevent. 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved declared Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted below reserve requirements. 1.3. Requirement R1 (in its entirety) does not apply: • (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or • (ii) after multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period, or • (iii) when the Responsible Entity is operating under the conditions described in R2, in its entirety. R1 Discussion: PJM views it as necessary to include the MW losses associated with units that may ramp down or be derated which also result in a loss of output or capacity. CR Form 1 needs to be modified to account for the suggested changes in R1. R2 Suggested changes: R2. The Responsible Entity shall

develop and maintain an Operating Plan to procure Contingency Reserve capacity for each hour greater than or equal to its Most Severe Single Contingency for that hour. R2 Discussion: PJM urges incorporation of our suggested revision to R2. PJM would be supportive of a standard that incorporated our proposed revision. This revision recognizes that the procurement of Contingency Reserves is accomplished in the Operation Planning time horizon and that R2 as presently drafted is overly prescriptive. R2.6 Suggested Changes: Should the presently drafted R2 and associated sub-requirements remain in the standard, PJM believes R2.6 is not acceptable in its present language. A necessary revision would be as follows: R2.6. in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve. available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. R2.6 Discussion: Load shedding plans are adequately addressed in the EOP standards. Requirement R2.6 as proposed is a distraction for the System Operator that has no positive impact on reliability. The requirement as written requires that Firm Load be shed to replace a shortfall of Contingency reserves. Why would an entity shed load to maintain reserves when shedding load via SCADA can be accomplished quicker than loading Contingency Reserves?
Group
ACES Standards Collaborators
Jason Marshall
ACES
(1) The Most Severe Single Contingency definition and applicability section 4.1.1.1 should be modified to reflect that the standard simply applies to a BA or RSG by striking “that is not participating as a member of a RSG at the time of the event”. This language may conflict with existing RSG contracts. Furthermore, it is a registration issue on whether the standard applies to the BA or RSG in these situations. When the RSG registers with NERC, NERC will typically review the contract to understand how the RSG is formed. If the standard should apply to the BA in certain situations and the RSG in others, this should be documented in a coordinated functional registration, not in a standards definition or applicability section. What does it even mean to be in “active status” under applicability section 4.1.1.1? (2) Please strike the last sentence of the Reportable Balancing Contingency Event. It is administrative in nature and should be handled through compliance monitoring processes. If NERC wants to know if an entity has modified its reportable threshold, they have a myriad of compliance monitoring processes and tools to gather this information. It does not need to be documented in a glossary definition. Furthermore, it is not really a definition but rather an explanation and therefore, does not belong in the definition. (3) We continue to believe that the thresholds defined in the Reportable Balancing Contingency Event are arbitrary. We ask that the drafting team provide a technical basis for the values instead of the existing explanation in the Background document. While we understand that the drafting team reviewed some data,

there are uncertainties regarding how values were identified from the data and then another value was selected. (4) We are confused about the “one-minute interval that defines a Balancing Contingency Event” language in the Contingency Event Recovery Period definition. We can find no reference to “one-minute” in the Balancing Contingency Event definition. There is, however, such a reference in the Reportable Balancing Contingency Event. Furthermore, the one-minute interval really does not define the event but rather pre-disturbance level before the start of the event. The language in the Contingency Event Recovery Period needs to be cleaned up to reflect this information. (5) We disagree with the definition of Contingency Reserve. The definition should be modified to simply reflect that Contingency Reserve Is unloaded on-line generation and quick start off-line generation capable of being dispatched in 15 minutes. The current definition may limit the use of Contingency Reserve and may omit off-line quick start generation since unloaded generation usually refers to on-line generators. (6) Reportable Area Control Error in the Rationale box for R1 should be changed to Reporting ACE to match the NERC Glossary. (7) The insertion of the “Reliability Coordinator approved” in Part 1.2 creates additional confusion by implying that an EEA can be issued without RC approval. An EEA cannot be issued without RC approval. Thus, this language is superfluous, only adds ambiguity and confusion to the part and should be struck. (8) Although, we do not oppose the use of CR Form 1, Part 1.1 should be struck as it is administrative in nature. A violation of Part 1.1 could never result in a harm to reliability. If an entity were to report the data in another format, reliability would not be harmed. If reliability cannot be harmed then a standard should not compel the action (in this case, specific use of a reporting form). Use of a CR Form 1 can and should be handled through NERC compliance monitoring processes as NERC and the Regional Entities do with other reporting formats and data collection methods. Use of CR Form 1 is already documented in the RSAW which should be sufficient. (9) While we appreciate that the drafting team did attempt to document other acceptable uses of Contingency Reserve in R2 that would not violate the requirement, we fundamentally disagree with the arbitrary selection of 90 minutes as a limit on the use of Contingency Reserve. Why should use of Contingency Reserve be limited to 90 minutes for an Energy Emergency? An Energy Emergency could last several hours and BA would be forced to either violate the requirement or shed load to avoid a compliance requirement. Neither is a good outcome. Rather, we suggest the 90 minute period should be dropped in Parts 2.1, 2.2, and 2.3. We particularly see this as an issue for Part 2.2. If an RC were to issue an Operating Instruction to use Contingency Reserve to resolve an EEA to avoid shedding load, why should this higher level authority not be able to instruct the BA to exceed the 90 minutes? The fact that Contingency Reserve may be used for longer than 90 is even documented in the second to last paragraph on page 36 of the background document. (10) We disagree with the arbitrary selection of five minutes in Part 2.6 for the exemption to apply. We believe the five minutes is arbitrary and language is ambiguous which will only lead to inconsistent compliance outcomes. What would be considered preparations? Sending techs to the stations? Arming loading shedding schemes? Thinking about it? There needs additional clarification in the standard. (11) We disagree with the move from quarterly reporting to exception reporting. Today, compliance is assessed on a quarterly basis. This standard appears to require a Responsible Entity to issue a self-report anytime it does not recover

100% from a reportable a Reportable Balancing Contingency Event without any basis identified for the change. This will serve to increase a Responsible Entities compliance costs without any commensurate benefit to reliability. Furthermore, it will eliminate a data source that NERC uses for its annual state of reliability report which will be detrimental to the report. (12) In Measure 2, we suggest adding a clause to the first bullet that Contingency Reserve must meet or exceed the required amount "unless one of the exceptions from R2 is met". (13) In Measure 2, we are confused by the language "excluded by rule in Requirement R2". Does this mean excluded by Parts 2.1 through 2.6? If so, change the language to "excluded by Parts 2.1, 2.2, 2.3, 2.4, 2.5 or 2.6". (14) The VSLs for Requirement R2 should be modified to state that Responsible Entity did have less than the required amount of Contingency Reserve "and did not meet one of the exceptions in Parts 2.1 through 2.6". (15) We are concerned that the requirement formatting of the exceptions in Part 2.1 through 2.6 are not consistent with the informational filing NERC submitted to FERC several years ago regarding the use of bullets and parts in place of sub-requirements. In that filing, NERC stated that numbered lists or "Parts" would be used when all "Parts" must be met and "bullets" would be used when there are exceptions. To qualify for an exception, only one of the Parts 2.1-2.6 should be met not all. Yet, use of a numbered list implies that all exceptions must be met. The formatting needs to be modified to bullets instead of a numbered list.
Individual
Christina Bigelow
ERCOT
ISO/RTO Council Standards Review Committee
ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. These concerns and recommendations are described below by Requirement. Proposed revisions are italicized. 1. Definitions – ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability. 2. Requirement R1 – Recommend modifying the addition (Reliability Coordinator Approved) to Reliability Coordinator Issued. 3. Requirement R1.2 and Requirement R1.3 – ERCOT recommends the consolidation of R1.2 and R1.3 and additional revisions as follows: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: • It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted. • It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency • It has experienced multiple Balancing Contingency Events

for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ERCOT recommends modifications to subpart 1 regarding the depletion of contingency reserves because contingencies that deplete reserves can occur without formal “activation” of reserves and without a “sudden” or triggering event. Thus, it respectfully suggests that the requirement should be modified to ensure that acknowledgment of such reserve depletion. ERCOT further recommends revision to subpart 1 because partially loaded generators may experience contingencies that remove MW from the BA, which may reduce the availability of reserves maintained by such resources as headroom. In such a circumstance, it is possible to have multiple contingencies where the MW loss is less than the MSSC, but that result in significant or complete reserve depletion for the BA. Accordingly, ERCOT recommends that subpart 3 be clarified to ensure that the loss to which the subpart would be applicable is clear and unambiguous. By accounting for overall MW of loss, not the magnitude of capacity loss, the applicability of Subpart 3 would be objective and easily discerned. 4. Requirement R2 –ERCOT respectfully submits that, as proposed, Requirement R2 would result in the unnecessary diversion of attention and resources during real-time operations to ensuring that data recordation and documentation occurred – rather than the performance of activities that are more directly associated with sustaining the reliability of the Bulk Electric System, e.g., contingency reserve mix, monitoring, deployments, etc. Accordingly, ERCOT respectfully suggests the following alternative revisions, which it believes more closely aligns with the Commission’s directives: R2. The Responsible Entity shall plan to procure Contingency Reserve greater than or equal to its Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or 2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or 2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or 2.4 in a Contingency Reserve Restoration Period; and/or 2.5 in a Contingency Event Recovery Period; and/or 2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Measure 2 could then be modified as follows: Compliance may be achieved by demonstrating that: • The Balancing Authority’s Operating Procedures require procurement of Contingency Reserve amounts that meet or exceed the Contingency Reserve required to respond to its Most Severe Single Contingency; or, • Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period; or, • the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency

Reserve level within the specified period; Failure of the Balancing Authority to procure adequate Contingency Reserve to respond to its MSSC and/or recover the required Contingency Reserve level within the time periods prescribed would be considered an exception and should be reported quarterly. ERCOT suggests this alternative because the directive being addressed required development of a continent wide contingency reserve policy, but did not require or prescribe tracking or reporting obligations. The proposed modifications appear to not only address a proposed reserve policy, but appear to also be revising the current quarterly reporting and prescribing an hourly tracking and recordation, actions and obligations for which ERCOT has been unable to identify an associated directive. Such additions will likely have unintended consequences in how Reserve Sharing Groups (RSG) will operate. In particular, the failure or delay of a contingency resource start can result in recovery performance that is assigned a very low score for that single event, even where recovery is only a minute or two late. Such outcome would be an inaccurate indicator of the overall success of the recovery, the overall recovery performance, and the Responsible Entity's efforts to recover. Further, there are RSGs whose purpose is to mitigate such risk by deploying reserves for much smaller events, helping reliability through quick recovery from smaller events, faster replenishment of reserves, and opportunity for operators to gain necessary experience regarding reserve deployment. Should each recovery event become individually sanctionable, RSGs will likely modify their rules to increase their reportable threshold to the interconnection minimum, which would reduce the net benefits to grid reliability discussed above. Additionally, the current quarterly reporting has provided an important data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx. The transition away from quarterly reporting to only exception reporting will eliminate that data source and reduce overall visibility. To facilitate the identification of exceptions while maintaining the value and benefits associated with quarterly reporting, ERCOT recommends that there be a single quarterly report for all data collected. In such a report, the Requirement R1 portion would be very similar to the current reporting form with an additional portion where instances of reserve amounts that were less than the MSSC during the quarter could be reported. Such coordinated reporting would allow both the ERO and the industry to evaluate reserve and contingency data concurrently, providing the opportunity to identify any trends and/or dependencies. ERCOT respectfully submits that the requirement to plan for and procure reserves greater than or equal to a BA's MSSC is an appropriate continent-wide contingency reserve policy and that such policy, when considered in coordination with obligations set forth within other approved reliability standards such as EOP-011-1 (Requirement R6), IRO-005-3.1 (Requirement R2), and TOP-002-2.1b (Requirements R5 – R8) are more than adequate to ensure reliability. Further, ERCOT would suggest that hourly calculation and/or demonstration of reserve amounts is: (1) not necessary when reserve requirements are considered in pari materia with other reliability standards obligations of BAs as described above, (2) unduly burdensome, and (3) a threat to reliability due to the diversion of resources that would be necessary to sustain compliance. Quarterly reporting of Reportable Balancing Contingency Events along with the reporting of reserve amounts less than a BA's MSSC are more than sufficient for both the ERO and responsible BAs to identify and address

contingency reserve issues that would threaten reliability. Hence, requiring BAs to provide documentation of contingency reserves averaged over a clock hour is an onerous, purely administrative obligation that elevates documentation over reliability. Thus, ERCOT recommends that Requirement R2 be revised as set forth above. ERCOT thanks you for the opportunity to comment upon the proposed Revisions to BAL-002-2 and respectfully suggests that, as NERC continues its effort to move away from zero defect standards, Requirement R2 be revised as recommended above to support that concept. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.
Group
Bonneville Power Administration
Andrea Jessup
Transmission Reliability Standards Group
BPA is in agreement with the proposed standard, however, believes there should be a clarifying comment in requirement R1. In R1, following both sub-bullets of R1, BPA would like to state: “For all subsequent events that occur during the initial Contingency Event Recovery Period, the Pre-Reporting Contingency Event ACE Value for that initial event must be used for the subsequent event(s).” Finally, BPA proposes that R2 2.6 spells out that it only pertains to an EEA3. The reason for this is that exemption only applies to EEA level 3 in EOP-011-1 Emergency Operations. In that new standard, EEA 3 is defined, in part, as a situation where “The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.” EEA 2 language clearly states that while a BA can no longer meet all of its expected energy requirements: “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.”
Individual
Richard Vine
California ISO
Agree
ISO/RTO Council Standards Review Committee
Group
ISO/RTO Council Standards Review Committee
Charles Yeung
SPP
1. The SRC generally supports R1. For clarity, and to address a concern that events that do not sudden as defined in the term “Balancing Contingency Event” (such as ramping, derating, etc.) are excluded from the recovery consideration, the SRC suggests the following minor clarification to R1 for consideration: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: • Zero,

(if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event, or, • It's Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event. (i.e., strike out (i) and (ii)) We further suggest Part 1.2 be revised to read: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: • It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or deleted. • It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. • It has experienced multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. 2. In our previous comments, the SRC stated that it found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. Note: ERCOT does not support this comment. 3. In addition, the proposed R2 has the following potential adverse consequences: • An increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, therefore, costing the rate payers additional monies for no increase in reliability (Note: IESO does not support this comment); • Operators not deploying reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability; and/or • Entities shedding firm customer load to maintain reserves to meet compliance with this requirement, which, again, is not the right action to take for reliability. 4. We understand that the intent of the proposed R2 is to require a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering other events that may reduce this amount. We believe this together with the recovery provision in R1 and the provision in Requirement R6 and Attachment 1 of EOP-011-1 would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: • When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) Note: ERCOT does not support this comment.

Additional Comments

Joe Spencer/SERC/OC Review Group

We have the following questions and concerns with the language in the Applicability subsections for 4.1. Section 4.1.1.1 is problematic in that it states that the RSG is the RE when BA's are in 'active status'. Active status is subjective and likely not a defined term in governing RSG agreements. Additionally, the definition cannot be applied consistently to both R1 and R2. Please consider the following examples where a BA is assumed to be actively maintaining its reserve allocation for the RSG.   o A BA experiences a Reportable Event in which it recovers ACE and reserves in accordance with R1 without requesting assistance from the RSG members. The BA is the RE even though it is in 'active status' in the RSG.   o For R2 compliance purposes, as long as the BA is actively maintaining its allocation of reserves in accordance with the governing RSG agreement, the RSG is the RE.   o Applicability for R2 is further complicated when the BA may participate in an RSG for only part of its footprint and maintains its allocation for the RSG while also maintaining additional reserves for the MSSC in the overall balancing area. In this example, both the BA and the RSG are may be RE's. We believe that to resolve these issues, the BA versus RSG applicability should be moved to the requirements themselves. The SDT could also consider explicitly stating that a BA is compliant under R2 when it maintains the average hourly reserves at least equal to its reserve allocation under the terms of the governing RSG agreement.R1 - clarity needs to be added to phase "(i) beginning at the time of" to explain how this phrase applies. 2. We recommend the following change to the proposed language of R1.1.R1.1 All Reportable Balancing Contingency Events will be documented using CR Form 1 [or an acceptable alternative.]â€ƒ3. We recommend the following change to the proposed language of R1.2.R1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.]R1.2 Comment: The proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet to be approved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R1 compliance exemption, making the BA even less able to meet its reserve requirements.Further, if a BA declares an EEA, indicating that it is unable to meet reserve requirements, and subsequently deploys some of its reserves to meet increased load does this constitute a deployment of contingency reserves under R1.2 and what evidence does the BA provide to demonstrate compliance?4. We recommend the following changes to the proposed language of R2.R2. The Responsible Entity shall maintain Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except during periods when the Responsible Entity is in: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] o a restoration period because it has used its Contingency Reserve for Contingencies that are not Balancing

Contingency Events. This required restoration begins when the Responsible Entity's Contingency Reserve falls below its MSSC and must not exceed 90 minutes; and/or o response to a Reliability Directive; and/or o a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period; and/or o an Energy Emergency Alert Level under which Contingency Reserves have been activated [or where the Responsible Entity has declared that it may be unable to meet reserve requirements due to system conditions.]R2 Comment: As stated in the comments for R1.2, the proposed language is counterintuitive and creates a compliance trap for the System Operator. A BA may declare an EEA3 (under the revised language of yet unapproved EOP-011) indicating that it is unable to meet reserve requirements, but must deploy some of those reserves even if there is no immediate need to do so, to receive an R2 compliance exemption, making the BA even less able to meet its reserve requirements.Additionally, absent the suggested language in the first bullet, a BA may receive a Reliability Directive from its RC (see IRO-001 R8) to deploy Contingency Reserves to mitigate a condition or event that is having an adverse reliability impact on the BES, but be non-compliant under R2 for following that directive.We believe that R2, as currently proposed, is unnecessary to satisfy the directive in FERC Order 693 to develop "a continent-wide contingency reserve policy", as this was accomplished with the development of Reliability Guideline: Operating Reserve Management that was approved by the NERC Operating Committee in October 2013. If, however, the SDT decides that it is necessary to keep the commodity obligations currently proposed in R2, we believe that the suggested R2 changes above will reduce unintended adverse reliability consequences while further reinforcing satisfaction of the directive. Additional Comments:The SDT has failed to demonstrate a performance need, in the form of negative historical trends for DCS recovery or compliance, for the proposed changes. Significant negative consequences of the proposed standard include but are not limited to:1) The proposed language moves this project from being a performance based standard to a commodity obligation.2) Creates a daunting and unnecessary administrative burden in tracking the commodity obligations set forth in Requirement 2. For example, the following are just a few of the evidence requirements in the RSAW: a. R2 requires dated documentation that demonstrates that hourly Contingency Reserves were at least equal to hourly MSSC. In a three year audit period that is 26,280 one hour intervals! b. Both R1 & R2 require dated documentation for all Reportable Balancing Contingency Events that occur when an EEA and Contingency Reserves have been activated. When an RE declares an EEA2 or EEA3, under the current TOP standard, they are declaring that they may be unable to meet required reserve requirements. When the load increases after the EEA has been declared and units that were previously providing CR are then dispatched higher to balance the increased load, does that constitute deploying CR? What evidence does the RE provide? 3) Increased customer costs absent a demonstrated reliability need as BA's are incented to purchase additional contingency reserves beyond that needed to recover from the loss of MSSC.4) Increased frequency variation as BA's are incented to change generation dispatch at the top of each hour to meet the R2 commodity obligation.5) Increased SOL & IROL exceedance durations as BA's are reluctant to deploy reserves to mitigate.6) As stated above, this standard creates a compliance trap for System Operators who may have to choose between activating reserves and shedding load for non-Reportable events OR following Reliability Directives under IRO-001 and maintaining reserves under BAL-002 R2.7) An increase in BAAL excursion minutes & frequency variation as BA's are discouraged from activating reserves for non-reportable events that are having an adverse impact on system frequency. 8) Provides a disincentive for a BA to assist its neighbor when a formal RSG Agreement is not in effect.9) The Severe VSL omits the "from a Reportable Balancing Contingency Event" language that is included in the Lower, Moderate, & High VSLs. We believe this omission was an oversight.10) The Background Document states on page 4 that “BAAL also ensures the Responsible Entity balances resources and demand for events of less magnitude than a Reportable Balancing Contingency” while R2 discourages the System Operator from using one of the important tools for accomplishing that task; Contingency Reserves.11) The Background Document states on page 5 that “FERC Order 693 (at 355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation”. Order 693 (at P355) directs the ERO to “define a significant deviation and a reportable event”. This misstatement in the Background Document is significant and should be corrected.12) The Background Document states on page 6 that “the drafting team elected to allow the Responsible Entity to use its Contingency Reserve while in a declared Energy Emergency Alert 2 or Energy Emergency Alert 3”. This statement is inconsistent with the current posting.13) The Background Document (Attachment 1) contains a series of box plots for each Interconnection labeled “Frequency Events Loss MW Statistics”. a. The SDT should include a summary of what this data represents, including event threshold criteria used to determine the sample. b. The data appears to show loss of generation and loss of load events in the same samples. If the intent is to show statistical correlation between the MW size of an event and magnitude of frequency deviation then loss of generation and loss of load events should be separated. c. Last step in example on Page 22 of the redline version, the -200 MW appears to be incorrect. The required ACE Recovery should be -600 MW. The comments expressed herein represent a consensus of the views of the above-named members of the SERC OC Review Group only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Dean Fox/Consumers Energy

Although the standard does not directly affect Consumers Energy, after reviewing the purposed standard and comments, I feel the intended goal to eliminate the ambiguities and questions associated with the existing standard has not been met. The new definitions and standard language confuse and complicate the issues.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Additional Ballot and Non-Binding Poll Open through March 16, 2015

Now Available

An additional ballot for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** and a non-binding poll of the Associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, March 16, 2015.**

Balloting – Legacy System
Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll by clicking here.

Note: If a member cast a vote in the previous ballot, that vote will not carry over to this additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in this ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

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 and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer Darrel Richardson (via email), or at 609-613-1848.

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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2

Formal Comment Period Open through March 16, 2015

Now Available

A 45-day formal comment period for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern on Monday, March 16, 2015.**

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 6 – March 16, 2015**.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Darrel Richardson, Standards Developer, or at 609-613-1848.

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Additional Ballot and Non-binding Poll Results

Now Available

An additional ballot for **BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern, Wednesday, March 18, 2015**.

The standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
77.29% / 59.83%	75.86% / 70.93%

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, make revisions to the standard and post it for an additional ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

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Ballot Results	
Ballot Name:	Project 2010-14.1 BARC BAL-002-2
Ballot Period:	3/6/2015 - 3/18/2015
Ballot Type:	Affirmative
Total # Votes:	262
Total Ballot Pool:	339
Quorum:	**77.29 % The Quorum has been reached**
Weighted Segment Vote:	59.83 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	89	1	43	0.729	16	0.271	0	13	17
2 - Segment 2	10	0.8	2	0.2	6	0.6	0	1	1
3 - Segment 3	75	1	31	0.646	17	0.354	0	12	15
4 - Segment 4	23	1	8	0.533	7	0.467	0	5	3
5 - Segment 5	71	1	32	0.727	12	0.273	0	10	17
6 - Segment 6	53	1	20	0.714	8	0.286	0	8	17
7 - Segment 7	2	0	0	0	0	0	0	0	2
8 - Segment 8	5	0.2	1	0.1	1	0.1	0	1	2
9 - Segment 9	3	0.1	1	0.1	0	0	0	0	2

10 - Segment 10	8	0.5	2	0.2	3	0.3	0	2	1
Totals	**339**	**6.6**	**140**	**3.949**	**70**	**2.651**	**0**	**52**	**77**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
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	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
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	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA)
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
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	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC RSC
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support NPCC comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted on behalf of PPL NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - ISO/RTO Council
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Richard 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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Abstain	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC and MRO NSRF)
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC and NPCC RSC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
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	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
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	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke

				Energy)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy	Richard Blumenstock	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer		
3	Detroit Edison Company	Kent Kujala		
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	SUPPORTS THIRD PARTY COMMENTS - PJM
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (GRE supports the NSRF comments.)
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		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - NSRF
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)

3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's CO-1 and CO-08 working groups)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Abstain	
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		
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
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	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Self	Herb Schrayshuen	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED

4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports PJM Comments)
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	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko		
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	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
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	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng		
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM Comments
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NSRF)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (DEF)
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	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		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	NextEra Energy	Allen D Schriver		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
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	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	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		
5	Tenaska, Inc.	Scott Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	

5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	NO COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports PJM comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's CO-1 and CO-08 working groups)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - ISO/RTO Council
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
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	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist		
7	Steel Manufacturers Association	James Brew		
8		Robert Blohm		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Debra R Warner	Debra R Warner	Abstain	
8	Energy Mark, Inc.	Howard F. Illian		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda D Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B Edge	Negative	COMMENT RECEIVED
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Non-Binding Poll Results

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-14.1 BARC BAL-002-2
Poll Period:	3/6/2015 - 3/18/2015
Total # Opinions:	242
Total Ballot Pool:	319
Summaray Results:	75.86% of those who registered to participate provided an opinion or an abstention; 70.93% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
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	Abstain	
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	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Abstain	

1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM Comments)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
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	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		

1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS - NPCC RSC
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supprts NPCC Comments)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted on behalf of PPL NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Richard 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	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Abstain	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC and MRO NSRF)
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
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	Affirmative	
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	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy	Richard Blumenstock	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala		
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	SUPPORTS THIRD PARTY COMMENTS - PJM Comments
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (GRE supports the NSRF comments.)
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		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Abstain	
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	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - NSRF
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC's CO-1 and CO-08

				working groups)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Omaha Public Power District	Blaine R. Dinwiddie	Abstain	
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		
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
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	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
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	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Abstain	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Self	Herb Schrayshuen	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	COMMENT RECEIVED
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Abstain	

4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports PJM comments)
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	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
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	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng		
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO)
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine		

5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - PJM Comments
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Gainesville Regional Utilities	Karen C Alford		
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom		
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		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	NextEra Energy	Allen D Schriver		
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Platte River Power Authority	Roland Thiel	Abstain	
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	

5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
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	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	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		
5	Tenaska, Inc.	Scott Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
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		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports

				PJM comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	Powerex Corp.	Daniel W. O'Hearn		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
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	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	

6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	EnerVision, Inc.	Thomas W Siegrist		
7	Steel Manufacturers Association	James Brew		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		Edward C Stein		
8		Robert Blohm		
8	Debra R Warner	Debra R Warner	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda D Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

The Project 2010-14.1 standard drafting team thanks all commenters who submitted comments on the BAL-002-2 standard. The standard was posted for a 45-day public comment period from January 29, 2015 through March 18, 2015 (including a 2-day extension to reach quorum on the ballot). Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 24 responses, including comments from approximately 116 different people from approximately 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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 Director of Standards, Howard Gugel (via email, howard.gugel@nerc.net), or at (404) 446-9693. 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/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.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	Jason Marshall	ACES Standards Collaborators	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Chip Koloini	Golden Spread Electric Cooperative	SPP	3, 5
3.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
4.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
5.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 3, 4, 6
6.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
7.	John Shaver	Southwest Transmission Cooperative	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Phillip Hart	Associated Electric Cooperative, Inc.	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	entral Electric Power Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
4. Group	Kelly Dash	Con Edison, Inc.	X		X		X	X				
5. Group	Colby Bellville	Duke Energy	X		X		X	X				
6. Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

3. Group — Andrea Jessup — Bonneville Power Administration

Additional Member	Additional Organization	Region	Segment Selection
1. Dave Kirsch	Technical Operations	WECC	1
2. Bart McManus	Technical Operations	WECC	1
3. Fran Halpin	Duty Scheduling	WECC	1

4. Group — Kelly Dash — Con Edison, Inc.

Additional Member	Additional Organization	Region	Segment Selection
1. Edward Bedder	Orange and Rockland Utilities	NPCC	NA

5. Group — Colby Bellville — Duke Energy

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

6. Group — Carol Chinn — Florida Municipal Power Agency

Additional Member	Additional Organization	Region	Segment Selection	
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Randy Hahn	Ocala Utility Services	FRCC	3
6.	Stan Rzad	Keys Energy Services	FRCC	4
7.	Don Cuevas	Beaches Energy Services	FRCC	1
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Javier Cisneros	Fort Pierce Utility Authority	FRCC	4

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	Matt Culverhouse	City of Bartow	FRCC	3
11.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
12.	Steven Lancaster	Beaches Energy Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Charles Yeung	ISO/RTO Council Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Christina Bigelow	ERCOT	ERCOT	2
2.	Mark Holman	PJM	RFC	2
3.	Kathleen Goodman	ISO-NE	NPCC	2
4.	Greg Campoli	NYISO	NPCC	2
5.	Terry Bilke	MISO	MRO	2
6.	Ali Miremadi	CAISO	WECC	2
7.	Ben Li	IESO	NPCC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Joe Depoorter	MRO-NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joseph Depoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
3.	Chuck Lawrence	American Transmission Company	MRO	1
4.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
5.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
9.	Larry Heckert	Alliant Energy	MRO	4
10.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
11.	Marie Knox	Midwest ISO Inc.	MRO	2
12.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
13.	Randi Nyholm	Minnesota Power	MRO	1, 5
14.	Scott Nickels	Rochester Public Utilties	MRO	4
15.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
17. Tony Eddleman	Nebraska Public Power District	MRO 1, 3, 5										
9. Group	Guy Zito	Northeast Power Coordinating Council	X	X	X		X	X		X	X	X

Additional Member	Additional Organization	Region	Segment Selection
1. Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2. David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3. Greg Campoli	New York Independent System Operator	NPCC	2
4. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5. Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6. Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7. Kathleen Goodman	ISO - New England	NPCC	2
8. Michael Jones	National Grid	NPCC	1
9. Mark Kenny	Northeast Utilities	NPCC	1
10. Helen Lainis	Independent Electricity System Operator	NPCC	2
11. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
12. Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13. Paul Malozewski	Hydro One Networks Inc,	NPCC	1
14. Bruce Metruck	New York Power Authority	NPCC	6
15. Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17. Robert Pellegrini	The United Illuminating Company	NPCC	1
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20. Brian Robinson	Utility Services	NPCC	8
21. Brian Shanahan	National Grid	NPCC	1
22. Wayne Sipperly	New York Power Authority	NPCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3. 'Aine Hasham-Lawence	PPL Generation, LLC	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			RFC	6
8.			SERC	6
9.			SPP	6
10.			WECC	6
11.			NPCC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	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
12.	Group	Robert Rhodes	SPP Standards Review Group	X	X			X					

Additional Member	Additional Organization	Region	Segment Selection
1. Darryl Boggess	Western Farmers Electric Cooperative	SPP	1, 5
2. Shannon Mickens	Southwest Power Pool	SPP	2
3. Jason Smith	Southwest Power Pool	SPP	2
4. Carl Stelly	Southwest Power Pool	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Kristie Cocco	Arizona Public Service Company	X		X		X	X				
14.	Individual	Richard Vine	California ISO		X								
15.	Individual	Christina Bigelow	ERCOT		X								
16.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
17.	Individual	Leonard Kula	Independent Electricity System Operator		X								
18.	Individual	Kathleen Goodman	ISO New England		X								
19.	Individual	Terry Bilke	MISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Jared Shakespeare	Peak Reliability	X									
21.	Individual	Catherine Wesley	PJM Interconnection		X								
22.	Individual	Anthony Jablonski	ReliabilityFirst										X
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Pamela 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				

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	Agree	Supporting Comments of "Entity Name"
California ISO	Agree	ISO/RTO Council Standards Review Committee
Hydro-Quebec TransEnergie	Agree	
ISO New England	Agree	NPCC RSC and IRC SRC
South Carolina Electric and Gas	Agree	PJM
ERCOT		ISO/RTO Council Standards Review Committee

1. **Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution.**

Organization	Question 1 Comment
ACES Standards Collaborators	(1) The Most Severe Single Contingency definition and applicability section 4.1.1.1 should be modified to reflect that the standard simply applies to a BA or RSG by striking "that is not participating as a member of a RSG at the time of the event". This language may conflict with existing RSG contracts. Furthermore, it is a registration issue on whether the standard applies to the BA or RSG in these situations. When the RSG registers with NERC, NERC will typically review the contract to understand how the RSG is formed. If the standard should apply to the BA in certain situations and the RSG in others, this should be documented in a coordinated functional registration, not in a standards definition or applicability section. What does it even mean to be in "active status" under applicability section 4.1.1.1? 0 (2) Please strike the last sentence of the Reportable Balancing Contingency Event. It is administrative in nature and should be handled through compliance monitoring processes. If NERC wants to know if an entity has modified its reportable threshold, they have a myriad of compliance monitoring processes and tools to gather this information. It does not need to be documented in a glossary definition. Furthermore, it is not really a definition but rather an explanation and therefore, does not belong in the definition. (3) We continue to believe that the thresholds defined in the Reportable Balancing Contingency Event are arbitrary. We ask that the drafting team provide a technical basis for the values instead of the existing explanation in the Background document. While we understand that the drafting team reviewed some data, there are uncertainties regarding how values were identified from the data and then another value was selected. (4) We are confused about the "one-minute interval that defines a Balancing Contingency Event" language in the Contingency Event Recovery Period definition. We can find no reference to "one-minute" in the Balancing Contingency Event definition. There is, however, such a reference in the Reportable Balancing Contingency Event. Furthermore, the one-minute interval really does not define the event but rather pre-disturbance level

Organization	Question 1 Comment
	before the start of the event. The language in the Contingency Event Recovery Period needs to be cleaned up to reflect this information. The language of a Balancing Contingency Event should be broader than that in the Reportable Balancing Contingency Event. The Reportable group is a subset of the BCE. (5) We disagree with the definition of Contingency Reserve. The definition should be modified to simply reflect that Contingency Reserve Is unloaded on-line generation and quick start off-line generation capable of being dispatched in 15 minutes. The current definition may limit the use of Contingency Reserve and may omit off-line quick start generation since unloaded generation usually refers to on-line generators. The drafting team disagrees with this over-simplification of what is or can provide contingency reserve. However, the SDT modified the definition based on industry comments received. (6) Reportable Area Control Error in the Rationale box for R1 should be changed to Reporting ACE to match the NERC Glossary. The drafting team agrees with this comment and has made the modification. (7) The insertion of the “Reliability Coordinator approved” in Part 1.2 creates additional confusion by implying that an EEA can be issued without RC approval. An EEA cannot be issued without RC approval. Thus, this language is superfluous, only adds ambiguity and confusion to the part and should be struck. We disagree with the statement that the language makes the statement ambiguous. A Balancing Authority may request that the RC issue an EEA. The language was put in the requirement to clarify that the EEA must be approved by the Reliability Coordinator prior to the entity being excused from the requirement. If the EEA is not declared until after the 15 minutes, then the entity is not excused. However the SDT modified the definition and removed the language. (8) Although, we do not oppose the use of CR Form 1, Part 1.1 should be struck as it is administrative in nature. A violation of Part 1.1 could never result in a harm to reliability.

Organization	Question 1 Comment
	If an entity were to report the data in another format, reliability would not be harmed. If reliability cannot be harmed then a standard should not compel the action (in this case, specific use of a reporting form). Use of a CR Form 1 can and should be handled through NERC compliance monitoring processes as NERC and the Regional Entities do with other reporting formats and data collection methods. Use of CR Form 1 is already documented in the RSAW which should be sufficient. The SDT is attempting to provide for consistency in reporting. (9) While we appreciate that the drafting team did attempt to document other acceptable uses of Contingency Reserve in R2 that would not violate the requirement, we fundamentally disagree with the arbitrary selection of 90 minutes as a limit on the use of Contingency Reserve. Why should use of Contingency Reserve be limited to 90 minutes for an Energy Emergency? An Energy Emergency could last several hours and BA would be forced to either violate the requirement or shed load to avoid a compliance requirement. Neither is a good outcome. Rather, we suggest the 90 minute period should be dropped in Parts 2.1, 2.2, and 2.3. We particularly see this as an issue for Part 2.2. If an RC were to issue an Operating Instruction to use Contingency Reserve to resolve an EEA to avoid shedding load, why should this higher level authority not be able to instruct the BA to exceed the 90 minutes? The fact that Contingency Reserve may be used for longer than 90 is even documented in the second to last paragraph on page 36 of the background document. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. (10) We disagree with the arbitrary selection of five minutes in Part 2.6 for the exemption to apply. We believe the five minutes is arbitrary and language is ambiguous which will only lead to inconsistent compliance outcomes. What would be considered preparations? Sending techs to the stations? Arming loading shedding schemes? Thinking about it? There needs additional clarification in the standard.

Organization	Question 1 Comment
	The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan (11) We disagree with the move from quarterly reporting to exception reporting. Today, compliance is assessed on a quarterly basis. This standard appears to require a Responsible Entity to issue a self-report anytime it does not recover 100% from a reportable a Reportable Balancing Contingency Event without any basis identified for the change. This will serve to increase a Responsible Entities compliance costs without any commensurate benefit to reliability. Furthermore, it will eliminate a data source that NERC uses for its annual state of reliability report which will be detrimental to the report. The SDT will work with NERC to ensure that they continue to get the necessary information for their reports and have that information added to the background document prior to the next posting. The individual event reporting moves the compliance process to meet the already used enforcement process. This also satisfies a FERC Order 693 directive. From Order 693 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters. (12) In Measure 2, we suggest adding a clause to the first bullet that Contingency Reserve must meet or exceed the required amount "unless one of the exceptions from R2 is met". The SDT has removed the language referenced.

Organization	Question 1 Comment
	(13) In Measure 2, we are confused by the language “excluded by rule in Requirement R2”. Does this mean excluded by Parts 2.1 through 2.6? If so, change the language to “excluded by Parts 2.1, 2.2, 2.3, 2.4, 2.5 or 2.6”. The SDT has removed the language referenced. (14) The VSLs for Requirement R2 should be modified to state that Responsible Entity did have less than the required amount of Contingency Reserve “and did not meet one of the exceptions in Parts 2.1 through 2.6”. The SDT has modified the requirement and therefore made modified the VSL’s accordingly. (15) We are concerned that the requirement formatting of the exceptions in Part 2.1 through 2.6 are not consistent with the informational filing NERC submitted to FERC several years ago regarding the use of bullets and parts in place of sub-requirements. In that filing, NERC stated that numbered lists or “Parts” would be used when all “Parts” must be met and “bullets” would be used when there are exceptions. To qualify for an exception, only one of the Parts 2.1-2.6 should be met not all. Yet, use of a numbered list implies that all exceptions must be met. The formatting needs to be modified to bullets instead of a numbered list. The SDT has modified the requirement.
PJM Interconnection	1. Please provide any issues you have on this draft of the BAL-002-2 standard and a proposed solution. 2. Comments: PJM appreciates and recognizes the work of the SDT as reflected in the present posting of the proposed BAL-002-2. PJM strongly urges the SDT to incorporate the following changes. 3. R1 Suggested changes:R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

Organization	Question 1 Comment
	o Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) (ii) by the magnitude of, each individual Balancing Contingency Eevent, or, o Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) (ii) by the magnitude of, each individual Balancing Contingency Event. 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved declared Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted below reserve requirements. 1.3. Requirement R1 (in its entirety) does not apply: o (i) when the Responsible Entity experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency, or o (ii) after multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period, or o (iii) when the Responsible Entity is operating under the conditions described in R2, in its entirety.

Organization	Question 1 Comment
	R1 Discussion:PJM views it as necessary to include the MW losses associated with units that may ramp down or be derated which also result in a loss of output or capacity. CR Form 1 needs to be modified to account for the suggested changes in R1. The SDT has modified Requirement R1. If you look at the definition of Reportable Balancing Contingency Event, you will see that they are limited to events that occur within a one-minute time period. In your example, either the event would not be reportable if the runback goes for more than one minute, or the runback MWs would be used to adjust the ACE recovery for the Reportable event. Does CR Form 1 allow for loss of unloaded capacity? R2 Suggested changes:R2. The Responsible Entity shall develop and maintain an Operating Plan to procure Contingency Reserve capacity for each hour greater than or equal to its Most Severe Single Contingency for that hour. R2 Discussion:PJM urges incorporation of our suggested revision to R2. PJM would be supportive of a standard that incorporated our proposed revision. This revision recognizes that the procurement of Contingency Reserves is accomplished in the Operation Planning time horizon and that R2 as presently drafted is overly prescriptive. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan R2.6 Suggested Changes:Should the presently drafted R2 and associated sub-requirements remain in the standard, PJM believes R2.6 is not acceptable in its present language. A necessary revision would be as follows: R2.6. in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve. available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.

Organization	Question 1 Comment
	The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan R2.6 Discussion:Load shedding plans are adequately addressed in the EOP standards. Requirement R2.6 as proposed is a distraction for the System Operator that has no positive impact on reliability. The requirement as written requires that Firm Load be shed to replace a shortfall of Contingency reserves. Why would an entity shed load to maintain reserves when shedding load via SCADA can be accomplished quicker than loading Contingency Reserves? The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan
ISO/RTO Council Standards Review Committee	1. The SRC generally supports R1. For clarity, and to address a concern that events that do not sudden as defined in the term "Balancing Contingency Event" (such as ramping, derating, etc.) are excluded from the recovery consideration, the SRC suggests the following minor clarification to R1 for consideration: R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: o Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event, or, o It's Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Contingency event that occurs shall reduce the required recovery: beginning at the time of, and by the magnitude of, each individual Contingency event. (i.e., strike out (i) and (ii)) We further suggest Part 1.2 be revised to read: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when:

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	o It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or deleted. o It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan o It has experienced multiple Balancing Contingency Events and/or Contingency events that are not Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. We disagree with this wording. Events greater than MSSC are excluded from R1 by definition of Reportable Balancing Contingency Event. 2. In our previous comments, the SRC stated that it found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. Note: ERCOT does not support this comment. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan 3. In addition, the proposed R2 has the following potential adverse consequences:

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	o An increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, therefore, costing the rate payers additional monies for no increase in reliability (Note: IESO does not support this comment); The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan o Operators not deploying reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability; and/or The SDT does not see any difference than what is currently required. o Entities shedding firm customer load to maintain reserves to meet compliance with this requirement, which, again, is not the right action to take for reliability. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan 4. We understand that the intent of the proposed R2 is to require a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering other events that may reduce this amount. We believe this together with the recovery provision in R1 and the provision in Requirement R6 and Attachment 1 of EOP-011-1 would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve requirement. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs

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	thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) Note: ERCOT does not support this comment. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Independent Electricity System Operator	1. In the last posting, we expressed a concern with the term "sudden loss" (see below). We are unable to find any response in the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a "Sudden loss of generation..." or "sudden decline in ACE...". The word sudden is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: "Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein." The SDT's response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. The term "sudden" is used in the definition of a wide category. This category may be used to refine the needed recovery for a Reportable Balancing Contingency Event under R1 in the proposed standard. The drafting team believes that as structured, the term "sudden" does not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another. While the example you provide works very well for the single entity that it covers, this type of structure is not likely to work for a nation-wide standard. The standard covers

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	entities such as relatively small Balancing Authorities like LADWP to very large entities such as PJM. Therefore a stated MW amount, or even a stated percentage would not treat all entities evenly or fairly. The drafting team supports the concept that each entity could provide further definition through written procedures to clarify how that entity implements their program. The drafting team disagrees with the need to add a sentence to the definition of Reportable BCE. The starting time of an event is determined by the definition of Pre-Reporting Contingency Event ACE Value. 2. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met the requirement in R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 with the following: R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted items may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to

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	exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Associated Electric Cooperative, Inc.	AECI respectfully requests that the SDT further consider modifying the Contingency Event Recovery Period to 30 minutes, or provide empirical evidence that demonstrates a risk to reliability exists when a Responsible Entity exceeds 15 minutes before recovering their ACE to the pre-disturbance level. Absent a risk to reliability when exceeding 15 minutes, the use of 30 minutes for the Contingency Event Recovery Period would more closely align with other reliability standards requirements that relate to operation of the BES during events, specifically the amount of time allowed for an entity to exceed an IROL. The existing standard requires 15 minute recovery for these events. The drafting team has not proposed to change the current recovery period. If the industry desires to change the recovery period to 30 minutes, studies would need to be made to determine the potential impact to reliability. The drafting team does not believe that a study can show less risk to the BES by extending the recovery period. It is unclear what could be shown to ensure that a longer recovery period would provide an Adequate Level of Reliability.
Con Edison, Inc.	Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material section: there is no substantial information contained in this section of the document. Is it the intent of the drafting team to fill-in these sections at a later date? If so, when would it be completed? If not, why not? This section may or may not be used in the standard. The SDT developed an Operating Reserve Guideline which could have been included in this section. However, the SDT decided to develop the guideline through the NERC Operating Committee. This allows for the guideline to be used for other standards and not just BAL-002.

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Arizona Public Service Company	APS would like the Drafting Team to clarify the following question about the draft language. R1.2 states "A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated." Since only a Balancing Authority can be declared to be in an RC-approved EEA, how would that impact the RSG that the Balancing Authority is a member of since that would be how they would be reporting their compliance with R1? Differently stated, does the RSG that the BA is a member of receive a waiver from R1 if the member BA is in an RC-approved EEA? If a Balancing Authority is experiencing an EEA event under which its contingency reserves have been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance. The RC should have gone through all steps prior to an EEA.
SPP Standards Review Group	BAL-002-2 Shouldn't 'transmission' as used in the definition of Balancing Contingency Event in A.a.iii. and B. be capitalized? Based on the drafting team's review of the defined term, we believe that the current term is more appropriate. Several standards recently have foregone the Effective Date section in the standard and instead refer to the Implementation Plan for the specific implementation dates. Should that be considered here? The SDT agrees and has made the necessary changes. Use lower case 'requirement' in the 3rd line of the Background material. (Did not look at this.) Contingency Reserve should probably be capitalized in the 1st, 2nd and 4th paragraphs of the Rationale Box for Requirement R2. The SDT has modified the requirement and therefore modified the rationale.

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	Delete the 's' on 'suites' in the 11th line of the 2nd paragraph of the Rationale Box for Requirement R2. The SDT has modified the requirement and therefore modified the rationale. Shouldn't 'load' be capitalized in the 4th paragraph of the Rationale Box for Requirement R2? The SDT has modified the requirement and therefore modified the rationale. Background Document Consistency is needed throughout the document in the capitalization of terms such as 'Transmission', 'Contingency Reserve', 'requirements', 'Transmission Line', 'Responsible Entity', 'Load', 'Real-time', 'energy deficient entities', 'event', 'field trials' and 'firm load'. In some situations, the SDT uses 'SDT' and in others it simply uses 'drafting team'. Be consistent throughout. Replace 'Balancing Authority or Reserve Sharing Group' with 'Balancing Authority (BA) or Reserve Sharing Group (RSG)' in the 9th line of the 3rd paragraph on Page 3. Subsequent uses of these terms should then be BA or RSG, respectively. Insert '(MSSC)' immediately following 'Most Severe Single Contingency' in the 2nd line of the 2nd paragraph on Page 4. Replace 'Standard' in the 6th line of the same paragraph with 'standards'. Replace 'the real-time operations' with 'Real-time operations' in the 1st line of the 1st paragraph under Balancing Contingency Event on Page 5. Replace 'requirement' with 'directive' in the last line of the 2nd paragraph under Balancing Contingency Event on Page 5.

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	Replace the 3rd bullet at the top of Page 7 with the following: ‘resolving the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) that requires the use of Contingency Reserves; and’. Replace ‘requirements’ with ‘directives’ in the 4th line of the 4th paragraph on Page 9. Replace ‘suites’ with ‘suite’ in the 1st line in the 1st paragraph at the top of Page 10. The SDT is to be commended for the improved clarity in the examples in Attachment 2. The reference sited in the last line of the 2nd paragraph on Page 34 (Footnote 5) is not attached. It’s referenced in Footnote 5. There is no Footnote 3 as referenced in the 3rd line of the paragraph under Control Performance Standards (CPS1) on Page 34. The SDT has reviewed the Background Document and believes that it has made all necessary corrections. CR Form 1 In cell A15 of the Read Me tab, use lower case ‘it’. In cell A1 of the Exemption tab, replace ‘Exemp’ with ‘Exempt’.In cells A10 and A16 of the Description tab, Â© appears instead of the intended (c). Thanks Microsoft. In cell A11 of the Entry Instructions tab, insert ‘with’ between ‘associated’ and ‘subsequent’. In cell A4 of the Calculator tab, insert ‘the’ between ‘Enter’ and ‘name’.
Bonneville Power Administration	BPA is in agreement with the proposed standard, however, believes there should be a clarifying comment in requirement R1. In R1, following both sub-bullets of R1, BPA would like to state:

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	”For all subsequent events that occur during the initial Contingency Event Recovery Period, the Pre-Reporting Contingency Event ACE Value for that initial event must be used for the subsequent event(s).” The SDT reviewed the requirement and determined that the present language sufficiently covered all situations. Finally, BPA proposes that R2 2.6 spells out that it only pertains to an EEA3. The reason for this is that exemption only applies to EEA level 3 in EOP-011-1 Emergency Operations. In that new standard, EEA 3 is defined, in part, as a situation where “The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.” EEA 2 language clearly states that while a BA can no longer meet all of its expected energy requirements: “An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.” The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan.
ERCOT	ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. These concerns and recommendations are described below by Requirement. Proposed revisions are italicized. 1. Definitions - ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated

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	documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability. FERC Order 693 states that the standard should address events that impact frequency in the interconnection. Based on review of events over the last 5 years, the levels in the definition address this event. 2. Requirement R1 - Recommend modifying the addition (Reliability Coordinator Approved) to Reliability Coordinator Issued. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan 3. Requirement R1.2 and Requirement R1.3 - ERCOT recommends the consolidation of R1.2 and R1.3 and additional revisions as follows: 1.2. A Responsible Entity is not subject to compliance with Requirement R1 when: o It is experiencing a Reliability Coordinator issued Energy Emergency Alert Level under which Contingency Reserves have been activated or depleted. o It experiences a Balancing Contingency Event that exceeds its Most Severe Single Contingency o It has experienced multiple Balancing Contingency Events for which the combined MW loss exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ERCOT recommends modifications to subpart 1 regarding the depletion of contingency reserves because contingencies that deplete reserves can occur without formal “activation” of reserves and without a “sudden” or triggering event. Thus, it respectfully suggests that the requirement should be modified to ensure that acknowledgment of such reserve depletion.

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The SDT has modified Requirement R1 and Requirement R2.
ERCOT further recommends revision to subpart 1 because partially loaded generators may experience contingencies that remove MW from the BA, which may reduce the availability of reserves maintained by such resources as headroom. In such a circumstance, it is possible to have multiple contingencies where the MW loss is less than the MSSC, but that result in significant or complete reserve depletion for the BA.
Accordingly, ERCOT recommends that subpart 3 be clarified to ensure that the loss to which the subpart would be applicable is clear and unambiguous. By accounting for overall MW of loss, not the magnitude of capacity loss, the applicability of Subpart 3 would be objective and easily discerned.
4. Requirement R2 -ERCOT respectfully submits that, as proposed, Requirement R2 would result in the unnecessary diversion of attention and resources during real-time operations to ensuring that data recordation and documentation occurred - rather than the performance of activities that are more directly associated with sustaining the reliability of the Bulk Electric System, e.g., contingency reserve mix, monitoring, deployments, etc. Accordingly, ERCOT respectfully suggests the following alternative revisions, which it believes more closely aligns with the Commission’s directives:
R2. The Responsible Entity shall plan to procure Contingency Reserve greater than or equal to its Most Severe Single Contingency, except during one or more of the following periods when the Responsible Entity is: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]
2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or
2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or
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	2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or 2.4 in a Contingency Reserve Restoration Period; and/or 2.5 in a Contingency Event Recovery Period; and/or 2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Measure 2 could then be modified as follows: Compliance may be achieved by demonstrating that: o The Balancing Authority's Operating Procedures require procurement of Contingency Reserve amounts that meet or exceed the Contingency Reserve required to respond to its Most Severe Single Contingency; or, o Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period; or, o the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency Reserve level within the specified period; Failure of the Balancing Authority to procure adequate Contingency Reserve to respond to its MSSC and/or recover the required Contingency Reserve level within the time periods prescribed would be considered an exception and should be reported quarterly.

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	ERCOT suggests this alternative because the directive being addressed required development of a continent wide contingency reserve policy, but did not require or prescribe tracking or reporting obligations. The proposed modifications appear to not only address a proposed reserve policy, but appear to also be revising the current quarterly reporting and prescribing an hourly tracking and recordation, actions and obligations for which ERCOT has been unable to identify an associated directive. Such additions will likely have unintended consequences in how Reserve Sharing Groups (RSG) will operate. In particular, the failure or delay of a contingency resource start can result in recovery performance that is assigned a very low score for that single event, even where recovery is only a minute or two late. Such outcome would be an inaccurate indicator of the overall success of the recovery, the overall recovery performance, and the Responsible Entity's efforts to recover. Further, there are RSGs whose purpose is to mitigate such risk by deploying reserves for much smaller events, helping reliability through quick recovery from smaller events, faster replenishment of reserves, and opportunity for operators to gain necessary experience regarding reserve deployment. Should each recovery event become individually sanctionable, RSGs will likely modify their rules to increase their reportable threshold to the interconnection minimum, which would reduce the net benefits to grid reliability discussed above. Additionally, the current quarterly reporting has provided an important data source that is used for NERC's RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx. The transition away from quarterly reporting to only exception reporting will eliminate that data source and reduce overall visibility. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. The drafting team is aware of only one RSG that currently uses a reduced minimum reporting threshold for their DCS compliance process. The other side of the debate on individual event reporting versus quarterly reporting includes the following points: 1. The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be

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	based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950) 2. Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity's failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability. In the discussion of a slower than anticipated start of a unit, there is no clear reasoning for how a determination of violation one failure in the quarter is adequately represented. If we assume that the total response provided in the quarter divided by the total response required in the quarter, only the MWs failed to be delivered matters, not the amount of time afterwards. Therefore, an individual event evaluation provides for a much better means to determine the impact to reliability from a single failure as opposed to a quarterly mishmash of all events. The drafting team believes that while a quarterly report may provide good data for trend analysis, it is a poor means to determine compliance. The drafting team is working with NERC staff to develop a process by which the quarterly information would still be available for the reports cited. However, the drafting team recommends that this data collection effort be outside of and separate from the compliance process. To facilitate the identification of exceptions while maintaining the value and benefits associated with quarterly reporting, ERCOT recommends that there be a single quarterly report for all data collected. In such a report, the Requirement R1 portion would be very similar to the current reporting form with an additional portion where instances of reserve amounts that were less than the MSSC during the quarter could be reported. Such coordinated reporting would allow both the ERO and the industry to evaluate reserve and contingency data concurrently, providing the opportunity to identify any trends and/or dependencies.

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	The drafting team is working with NERC staff to develop a process by which the quarterly information would still be available for the reports cited. However, the drafting team recommends that this data collection effort be outside of and separate from the compliance process. ERCOT respectfully submits that the requirement to plan for and procure reserves greater than or equal to a BA's MSSC is an appropriate continent-wide contingency reserve policy and that such policy, when considered in coordination with obligations set forth within other approved reliability standards such as EOP-011-1 (Requirement R6) (EEA), IRO-005-3.1 (Requirement R2) (RC must monitor Con. Res., due to be retired when new IRO standards are approved), and TOP-002-2.1b (Requirements R5 - R8) (also due to be retired with new TOP standards, did not look for requirement mapping) are more than adequate to ensure reliability. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan Further, ERCOT would suggest that hourly calculation and/or demonstration of reserve amounts is: (1) not necessary when reserve requirements are considered in pari materia with other reliability standards obligations of BAs as described above, (2) unduly burdensome, and (3) a threat to reliability due to the diversion of resources that would be necessary to sustain compliance. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. Quarterly reporting of Reportable Balancing Contingency Events along with the reporting of reserve amounts less than a BA's MSSC are more than sufficient for both the ERO and responsible BAs to identify and address contingency reserve issues that would threaten reliability. Hence, requiring BAs to provide documentation of contingency reserves

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	averaged over a clock hour is an onerous, purely administrative obligation that elevates documentation over reliability. Thus, ERCOT recommends that Requirement R2 be revised as set forth above. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. ERCOT thanks you for the opportunity to comment upon the proposed Revisions to BAL-002-2 and respectfully suggests that, as NERC continues its effort to move away from zero defect standards, Requirement R2 be revised as recommended above to support that concept. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.
Florida Municipal Power Agency	FMPA supports the comments of Duke Energy
Duke Energy	General Comments: Duke Energy would like to take the opportunity to offer comment on the overall project concerning BAL-002-2 in conjunction with the recent FERC NOPR issued on November 20, 2014. FERC issued a NOPR proposing the approval of the BAL-001-2 standard (Real Power Balancing Control Performance). FERC commented in its NOPR that further revisions to the BAL-002 standard should take into consideration, the impact the revisions may have on the Balancing Authority ACE Limit (BAAL) in BAL-001-2. Duke Energy agrees with the Commission that the potential impact that compliance with BAL-002 may have on BAAL should be taken into consideration during further modifications to BAL-002, and suggests that this project be tabled until the final order issuing the approval of BAL-001-2 has been handed down by FERC. While we may agree with the premise, the current standard needs to be either replaced or retired sooner rather than later. This revision addressed the problems with the existing standard while keeping essentially the same thing in place. Balancing Contingency Event: Duke Energy would like to re-state its concerns with the proposed definition of Balancing Contingency Event. Originally, we stated that we sought

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	clarification on item B of the Balancing Contingency Event (BCE) definition. A BCE should be predicated on a deviation in Area Control Error (ACE) . As written, we are unclear why item B is even part of the definition because we believe Item B is redundant with item A.a.ii. We fail to see the additional clarity that Item B provides, and could see where questions could arise regarding the differences between the two items in the future. The SDT disagrees with this statement and feels that the present language is sufficient. Also, this comment does not appear to be supported by the majority of the industry. Background: In the revised background section of the proposed BAL-002-2, the section alludes to frequency management, however, we fail to see any requirement in this standard pertaining to frequency management. The SDT is not trying to say that BAL-002 provides frequency management. We are only pointing out that some parts of BAL-002 can influence frequency management. R1: We would like to offer our previous comment on this requirement for the drafting team's consideration. Duke Energy suggests the following revision to R1.2: "1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing an Energy Emergency Alert under which Contingency Reserves have been utilized to serve load." We believe the intent of the SDT was for the Responsible Entity to be exempt from compliance with R1 during those instances where Contingency Reserves are utilized to serve load. Duke Energy requests further clarification on what is meant by the reference to activate Contingency Reserves under an Energy Emergency Alert (EEA). R1 Rationale: If the SDT's intent is to eliminate any potential overlap with other standards, this will not be the case once the BAAL is in place. If BAL-001-2 is approved, there will be another standard driving a BA to take corrective action when frequency is hurting. Again, we caution the SDT that moving forward with the BAL-002-2 project without taking into consideration the BAAL, could result in conflicting standards. In addition, we believe that there are situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. For example, as the Disturbance Control Standard ("DCS") under BAL-002 is measured event-by-event, a Balancing Authority is required to return its

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	ACE to zero with 15-minutes after a Reportable Disturbance (or back to its pre-Disturbance ACE value if that value was negative). Such a response in the future may be a problem if the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2. If a generation resource was lost in the middle of the night during a period of minimum load concerns, numerous available generation resources, and high Interconnection frequency, BAAL would drive the Balancing Authority to take appropriate action over a reasonable timeframe. DCS would not consider any of these factors but would require the Balancing Authority to strictly comply. This strict compliance with BAL-002 could have a detrimental impact on Interconnection frequency. In the description of the EEA Level 3, it states that Contingency Reserves are being used to serve load. Your understanding of the intent is correct. The drafting team modified the language to provide clarity. R2: Duke Energy requests further clarification from the drafting team on whether its intent was for the standard to be worded in such a manner to allow for the waiving of immediate restoration of reserves. Is it the SDT's intent to afford an entity the opportunity to wait for a period of 90 minutes, before requiring the restoration of reserves to take place? As written, the auditable requirement is for reserves to be restored within 90 minutes. While the current language of the standard suggests it should be completed faster, the actual compliance check point is at 90 minutes. The SDT also added Requirement R3 to provide additional clarity. Also, Duke Energy suggests a re-ordering of the sub-requirements for R2. Sub-requirements 2.4 and 2.5 should be first and second on the list of sub-requirements based on the reasoning that they would be the most common instances. Regarding sub-requirement 2.6, we feel that clarifications are needed. As written currently, it is unclear whether an entity has to actually shed load for 2.6 to apply, or if you have to just be prepared to do so. There are concerns that requiring compliance

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	documentation to demonstrate that you were prepared to take some action, even though said action never took place, could be considered onerous. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan Lastly, upon our review, it could be argued that some of the sub-requirements appear to mirror closely responsibilities that are already present in EOP-002. We suggest that the SDT consider delaying implementation of BAL-002-2 so that it becomes effective after EOP-011-1. The SDT has modified the requirement to have a process for Contingency Reserve in their Operating Plan.
Peak Reliability	General: BAL standards should be developed as a group and not individually. R1.2: “A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.”EOP-002-3.1 speaks to the RC initiating/declaring but not approving an Energy Emergency Alert. It can be argued that parameters are in place to make a decision on approval but nevertheless there is no mention of approvals nor defined approval processes within the standard. Suggestion is to revise from “approved” to “initiated/declared” to remain consistent with EOP-002-3.1. The SDT has removed the language referenced and modified the requirement. R2: Peak is concerned that using an average clock hour might allow entities to take advantage. For example, if an entity is deficient the first 30 minutes but sufficient the second 30 minutes, the average clock hour would be met but the first 30 minutes would be in an unreliable state. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan

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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	In regards to R2.6: In an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared. Southern agrees that a BA should not be required to maintain Contingency Reserves during an applicable Energy Emergency Alert level (for Southern that would be an EEA3). Our concern is with how the following sentence is phrased "For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared." We recommend a different approach so that it reads, "For this exemption to apply, the deficient BA must be able to execute interruption of Firm Load to restore ACE within the Contingency Event Recovery Period timeframe". The rationale behind this change is if a deficient BA can recover ACE within Contingency Event Recovery Period via load shed this should be an acceptable practice but they must have the ability to execute completely this action within the Contingency Event Recovery Period timeframe (e.g. 15 minutes). Southern agrees with the drafting team that in an EEA3 a BA should be able to consider load shed as a viable practice to maintain ACE and not be required to re-establish Contingency Reserves by shedding load pre-contingency. The current way the Measure is worded supports this purposed change. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan
ReliabilityFirst	ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1 - ReliabilityFirst suggests using the word "shall" instead of "will" to make mandatory the use of the noted CR Form 1. The term "shall" indicates a duty on the subject and is used throughout the NERC Standards in this manner; in this case the responsible entity has a duty to use CR Form 1, so "shall" is the more appropriate term. ReliabilityFirst recommends attaching it to the standards along with

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	the following change for consideration: "The Responsible Entity shall document all Reportable Balancing Contingency Events using Attachment 1 - CR Form 1." The SDT is attempting to provide for consistency in reporting. 2. Measure M2 - The newly included second paragraph within Measure M2 reads more as an exception to the requirement and does not belong as a measure. It appears to be guidance to an auditor and should more appropriately be placed in an RSAW. Furthermore, ReliabilityFirst does not want to encourage missing data as a reason for not performing the calculation and believes any or as many valid samples of the Contingency Reserve should be included in the clock hour and should not be excluded from the evaluation. ReliabilityFirst recommends completely removing the second paragraph within Measure M2 from the standard. The SDT has modified the requirement and therefore made modified the measure accordingly.
Seattle City Light	Seattle City Light supports Balancing Authorities having the flexibility to use Contingency Reserve to respond to other reliability events and votes affirmative for this ballot. Seattle would support the draft more, however, if the term "clock hour average" was replaced with "instantaneous value" throughout the Standard. Using Hourly averages places entities in the position where they may be incentivized to have less Contingency Reserve than their current Most Single Severe Contingency for large percentages of key operating hours. From a financial perspective, there is nothing in this revision stopping a Balancing Authority from having less Contingency Reserves than their Most Single Severe Contingency during the last 20 to 30 minutes of every steep load pick up hour every day. While theoretically possible, this operating practice would subject an entity to violation of one or both requirements if an event occurs during the ramp period. (In other words, one bad day and it will never happen again.)

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Northeast Power Coordinating Council	There is a possible inconsistency in the terms Balancing Contingency Event, and Reportable Balancing Contingency Event. Balancing Contingency Event is defined as “Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by less than one minute...” Reportable Balancing Contingency Event is defined as “...(ii) the amount listed below for the applicable Interconnection, and occurring within a one-minute interval of the initial sudden decline in ACE...” By its definition, the Balancing Contingency Event, in the extreme, is an unlimited number of single events, as long as they are separated by less than one minute. Is it intended for a Reportable Balancing Contingency Event to only encompass what happens in the first minute as it is worded? Yes, if an event takes longer than a minute to unfold, it makes the measurement process impossible. Therefore the standard only covers those events that meet the exact definition of Reportable BCE. The set of Balancing Contingency Events would by definition be either equal to or more than likely greater than the Reportable BCE set. In the NERC Glossary, Reportable Disturbance is defined as “Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority’s or reserve sharing group’s most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.” The definition of Reportable Balancing Contingency Event should be revised to incorporate this definition, and should be made to read”...(i) Reportable Disturbance, or...”. With this revision, when BAL-002-1 is retired the definition of Reportable Disturbance can be retired as well. The SDT is looking into this possibility. Regarding the Rationale for Requirement R1, should Reportable Area Control Error be Reporting ACE? Reporting ACE is in the NERC Glossary, Reportable Area Control Error is not. The SDT agrees and has made the change.

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	In the second paragraph of the Rationale for Requirement R1 that reads"...as described in R1.3 below..." should be revised to read "as described in Part 1.3...". The SDT agrees and has made the change. Measure M1 should be revised to read "...that demonstrates compliance with Parts 1.2 and 1.3.". The SDT agrees and has made the change. In Requirement R2, and Measure M2 "Firm" should not be capitalized. "Firm Load" is not in the NERC Glossary. It should be revised to read firm Load. The SDT has modified the requirement and therefore made modified the measure accordingly. Additional comments: 1) The proposed standard continues with several "compliance traps" which will hamper operators' effective use of Contingency Reserves to mitigate reliability problems, and then could cause compliance exposure due to auditor interpretation. For example, R1 would require a BA to deploy at least some of its reserves in order to declare an EEA exemption even if there may not be an immediate need to do so. The SDT has modified the language and believes that your concern has bewen addressed. 2) There are contradictory portions of the standard which would leave operators confused and again lead to compliance exposure. a. For example, Part 1.3 (ii) does not include an exemption for deploying Contingency Reserve for a Contingency that is not a NERC defined Balancing Contingency Event. R2 does have an exemption for this and other scenarios. The term "sudden" being included in the definition of a Balancing Contingency Event is

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	the source of the problem. See the second scenario of Attachment A (sent by E-mail to Darrel Richardson). The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan b. R1 does not treat subsequent Contingencies in a consistent manner, again related to the term "sudden" being included in the definition of a Balancing Contingency Event. See the first scenario in Attachment A (sent by E-mail to Darrel Richardson). The term “sudden” is used in the definition of a wide category. This category may be used to refine the needed recovery for a Reportable Balancing Contingency Event under R1 in the proposed standard. The drafting team believes that as structured, the term “sudden” does not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another. While the example you provide works very well for the single entity that it covers, this type of structure is not likely to work for a nation-wide standard. The standard covers entities such as relatively small Balancing Authorities like LADWP to very large entities such as PJM. Therefore a stated MW amount, or even a stated percentage would not treat all entities evenly or fairly. The drafting team supports the concept that each entity could provide further definition through written procedures to clarify how that entity implements their program. The drafting team disagrees with the need to add a sentence to the definition of Reportable BCE. The starting time of an event is determined by the definition of Pre-Reporting Contingency Event ACE Value. 3) There are several problems with the definitions including definitions of Most Severe Single Contingency (MSSC), Contingency Event Recovery Period (CERP), and Balancing Contingency Event (BCE).

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	a. MSSC does not include concurrently dropped load which may cause a Balancing Authority to carry extra Contingency Reserve beyond its actual MSSC. If load is dropped concurrently, the size of the event is the size of the generator, the load that drops is reserve for that event and the response requires only an amount of additional reserve over and above the net amount. It should be pointed out that if this load does not drop for the loss of another unit, the actual amount of reserve needed may be more than the net amount, depending on the size of the next largest contingency. b. BCE is unclear with regard to both generation and transmission events. (Also consider if A. Item b within the BCE definition instead referred to an unplanned change in ACE as opposed to an unexpected change in ACE.) 4) Regarding R2: a. R2 is far more complex than necessary, is unclear, and contains potential for gaming. b. Much less complicated language is proposed here, based on the original NERC Policy 1. Suggest the revision of R2 to read: R2. The Responsible Entity, if deficient in Contingency Reserves, has 90 minutes to restore. If the Responsible Entity experiences a Reportable Balancing Contingency Event during this time an additional 15 minutes are allotted." An alternative suggested rewording of R2:R2. The Responsible Entity shall develop operational plans that provide sufficient Contingency Reserve considering all other events that may reduce this amount. This, together with the recovery provision in R1 (results-based requirement) and the provision in Requirement R6 and Attachment 1 of EOP-011-1 (which defines EEA levels) would collectively take care of many of the conditions listed in the proposed Requirement R2 including active monitoring of the amount of reserve to meet the Contingency Reserve

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	requirement. R2 as presented in this draft requires a BA to demonstrate that it maintains Contingency Reserve, averaged over each Clock Hour, greater than or equal to its average Clock Hour Most Severe Single Contingency, except under certain circumstances. If the SDT's intent is to ensure that a BA consider events other than MSSC that could reduce the amount of reserve, then to meet this intent we suggest replacing R2 as shown preceding. We believe this together with the recovery provision in R1 would take care of many of the conditions listed in the proposed Requirement R2. c. The language in Part 2.2 regarding Operating Instruction appears to allow operating personnel to create exemptions from R2 at will. The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan d. Requirement R2 continues to not include a number of "grace hours" per quarter, as requested in some industry comments. It may have a net effect of increasing the amount of available contingency reserve to some BAs which may marginally increase reliability. However, this needs to be balanced against increased operating costs due to carrying more reserve. e. Requirement R2 may produce a perverse incentive. A BA may let its ACE remain negative to keep the reserve monitor numbers above MSSC. Also, without a number of "grace hours" per quarter, there may be a susceptibility to loads running unexpectedly high near the end of a Clock Hour, causing a miniscule shortfall that results in an occasional "nuisance" compliance violation. f. R2 also causes BAs to carry much higher Contingency Reserves than necessary during the latter portions of the hour in order to "make the numbers come out right" if they are below MSSC in the beginning of the hour. g. Requirement R2 creates an artificial increase in reserves in order to maintain an amount over-and-above that required by the standard to meet non-DCS operational events, thereby increasing costs to ratepayers for no increase in reliability.

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	h. R2 will encourage operators to not deploy reserves when needed for reliability in order to meet compliance with this requirement, which could be detrimental to reliability. i. Entities that have to shed firm customer load (because load cannot be shed fast enough) to maintain reserves to meet compliance with this requirement is not an action that should be taken for reliability. j. In our previous comments, we found Requirement R2 confusing and that the requirement itself was unnecessary for so long as the BA met requirement R1. Having R1 that requires a BA to meet the ACE recovery requirement following an MSSC event would suffice to drive the proper behavior of securing adequate reserve around the clock (except those conditions listed in R1). If and when a contingency occurs and the affected BA does not have sufficient reserve to recover ACE, then it will fail R1 whereas if R2 as presented is retained, then a BA could fail both requirements. There is no need for having R2 to support R1, which can result in double jeopardy. k. To include the remaining conditions that are not already accounted for under which a BA may not be able to maintain the required amount AND during which an MSSC event occurs thereby rendering a BA unable to meet requirement R1, then the following bulleted item may be added under Part 1.3 in R1: o When the Responsible Entity is using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the excedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL). 5) The last sentence of metric M2 which splits a Clock Hour into sub-periods is difficult to follow and seems to add unnecessary complexity in determining compliance. 6) When the exemption in Part 2.6 becomes relevant, it most likely will occur within the middle of a Clock Hour. It is not clear if "instantaneous values showing reserves" refers to the sum of Contingency Reserve available plus Firm Load that can be shed. 7) Part 1.3 and R2 should be cognizant of unexpected loss of reserve without it being accompanied by a loss of power being delivered. In the last posting, we expressed a concern with the term "sudden loss" (see below). We are unable to find any response in

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	the Summary Consideration report that addresses this comment. Please consider these comments and provide a response. A Balancing Contingency Event is vaguely defined as a “Sudden loss of generation...” or “sudden decline in ACE...”. The word “sudden” is imprecise, and should be clarified. We suggest that the standard be clearer about defining the start time for a Reportable BCE. We support definitions like that used in NPCC Directory 5 section 5.17 where it says that the start of an event has occurred when a specific X amount of MWs are lost in a specific Y amount of time. Therefore, we suggest that the drafting team add precision in determining minute T+0 for an event by adding the following sentence (or something like it) to the Reportable BCE definition: “Following the resource failure, the Reportable BCE starting time is defined as the first chronological rolling one minute interval that meets the reduction in resource output(s) criteria stated herein.” The SDT’s response to comment does not appear to address this particular comment. We ask the SDT to please provide the rationale as to why this suggestion was not adopted. The SDT has removed the language referenced and modified Requirement R2 to have a process for Contingency Reserve in their Operating Plan To summarize, the January 2015 version of BAL-002-2 could be improved by providing better clarity within the definitions and making simplifications that yield a more "operator-friendly" standard. There is a concern that the complexity and nuances of the proposed standard in some circumstances could be a distraction to the operator when more important reliability tasks need to be performed. The standard is complex because the issues we are addressing are many and interrelated. A simple standard would be: R1, Correct your ACE within 15 minutes of the loss of a resource R2. Replace any Contingency Reserve within 105 minutes of the loss of a resource R3. If no resource is lost, Contingency Reserve must equal an entity’s MSSC for each data point base on the entity’s SCADA scan rate.

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	This would not provide the necessary information to be able to consistently define compliance within the standard and to date has not been supported by the majority of the industry.
PPL NERC Registered Affiliates	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.The PPL NERC Registered Affiliates support the comments provided by PJM. In addition, we submit the following comments: It is not clear how the compliance exemptions in R1.2 and R2.6 for a Responsible Entity experiencing an EEA would apply to a RSG. Since an RSG cannot request the RC to declare an EEA , it appears the RSG would be required to maintain MSSC level reserves regardless of the EEA status of its member BAs. It also appears the RSG could be found non-compliant with both R1.2 and R2.6 simultaneousl. We suggest that while a member of a RSG is in an EEA, its MSSC and Contingency Reserve Requirement (the member BA's reserve obligation to the RSG) are removed from the RSG. The reconfigured RSG would continue to maintain the RSG based on the new MSSC and the revised assignment of CRR among the non-EEA members. The RSG would remain in this configuration for the duration of the member BA's EEA. The SDT does not completely agree with your comment. This assumption is possible for some RSGs but may not be possible for all RSGs. Assigning a Medium VRF to both R1 and R2 is not appropriate - the reliability impact of not having the required amount of reserves does not seem comparable to the reliability impact of not recovering ACE after a reportable BCE. The VRF for R2 should be lower than R1. If R2 cannot be revised as suggested by PJM, an alternative to the average Clock Hour measurement period should be provided. If reserves dip below the MSSC late in a Clock Hour, it is doubtful if a RE could act in time to resolve the shortfall. Also, what is the

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	reliability benefit of an RE acting to increase its reserves if the shortfall occurs earlier in the hour? It doesn't seem the average Clock Hour measurement period provides an RE much flexibility in complying with R2 nor does it improve BES reliability. A rolling hourly average or multi-Clock Hour average would be an improvement. The SDT has removed the language referenced and modified the requirement to have a process for Contingency Reserve in their Operating Plan. The SDT feels that neither of the requirements would definitely cause cascading outage but there is the possibility. For this reason the SDT believes that a medium VRF is correct. This also agrees with the current similar requirements VRFs. BAL-002-2 directly applies only to BAs and Reserve Sharing Groups, but it states in the definition of Contingency Reserve that the capacity mandated, "may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation." That is, BAs can fulfill their BAL-002-2 obligations only by imposing demands on these other parties, and we would like to know up-front what they will be. This standard does not allow BAs to impose demands upon other parties. It allows a BA to provide the reserves from essentially any resource that meets the definition and intent of the response needed for compliance. This concern is heightened by the addition (effective 4/1/2015) of the expression, "and discourage response withdrawal through secondary control systems," to the NERC Glossary definition of Frequency Bias Setting. This change echoes the statement, "appropriate outer-loop controls (distributed controls) settings to avoid primary frequency response withdrawal," in the NERC Resource Subcommittee's 2013 Eastern Interconnection Frequency Initiative Whitepaper," and "Related outer-loop controls within the DCS, as well as applicable generating unit or plant controls, should be set to avoid early withdrawal of primary frequency response," in NERC's 2/5/2015 Industry Advisory, Generator Governor Frequency Response." Implementation of appropriate governor time delays and droop settings constitutes a well-defined and technologically justified form of GO involvement in frequency response improvement, but the term "response withdrawal" is vague and could cause BAL-002-2 to be misconstrued as

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	authorizing BAs to demand new, frequency response-enhancing services from GOs as a regulatory requirement rather than obtaining them through market mechanisms. The SDT believes that there is some confusion here. For clarity, Contingency Reserve response has nothing to do with the issue raised in your comment. Contingency Reserve response is measured over a 10-15 minute period, not the time periods discussed in the referenced document.
MISO	We commend the drafting team on the effort committed to this project and appreciate the improvements. We also appreciate the various objectives the team is trying to meet, but believe it is time to step back and ensure we are moving in a direction where NERC is trying to go with clearer, results-based standards. We understand that the team is trying to meet their interpretation of Order No. 693 directives. We respectfully submit that much of what the FERC directed may be moot as the directives related to primary, secondary, and tertiary control, have been met by other standards projects. This is particularly true considering the equally effective R2 (Balancing Authority ACE Limit, BAAL) in BAL-001-2 and a performance based Frequency Response Standard. The current BAL-002 is well understood by system operators and performance as posted on the NERC "Adequate Level of Reliability (ALR) Metrics" website has been stellar. The draft out for comment is not easily understood, adds complexity, and will likely increase customer cost for no discernable reliability value. The drafting team will only point to the existing interpretation and NOPR proposed by FERC to remand the interpretation and state that while MISO may operate based on their understanding of tradition and history, there is obviously a clear disconnect between the regulatory interpretation of the current standard and the industry's interpretation of the existing standard. IF the regulated and regulators cannot agree on what the standard says, then it obviously needs corrected. The drafting team believes that taking a standard from 6 requirements to 2 requirements while essentially continuing to operate as history would show has been done is not a significant change.

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	If the standard effort reaches an impasse, it may be time to hold a technical conference to get resolution on a few key items: 1] What should be the obligation of the Balancing Authority for events > MSSC? [We suggest that such events are reported to demonstrate best efforts were made, but compliance is not assessed. The BA is still accountable for BAAL. Finally there are backstop standards as load shedding is mandated in the EOP and IRO standards for harmful frequency conditions and IROL exceedances] The drafting team agrees with this position. We also believe that this is what the existing standard says. Clearly our regulators do not. Both industry and our regulators agree that this proposed standard does say that. 2] What constitutes a continent-wide contingency reserve policy? [We believe the policy could be met by developing simple definitions for the various categories of operating reserves as any can be used to meet DCS or the other Balancing Standards in real time. The policy should state that the BA performs an analysis to develop warning and alarm points for their operators for the reserves needed to meet BAL-001, BAL-002, and BAL-003. Having BAs provide this data to in real time to their Reliability Coordinators would add reliability value to the EEA and other EOP processes. Finally, a guidelines document on reserves approved by the NERC Operating Committee could be part of this policy] 3] Since there are now performance based BAAL and FRS in place, could we not actually simplify the current DCS? [Retain a cleaner version of the current R1, and a simpler R2 that requires presenting reserve values to BA and RC with appropriate alarm points] 4] The extent the remaining 693 directives have been met by other standards projects. [We believe BAAL addresses the Commission's concerns for detecting and responding to significant high or low frequency events, addresses the concern about performance to individual events, and is a performance-based double-confirmation of secondary and tertiary reserves] 5]For those requirements that are ultimately proposed, is there a way to keep them simple and easy to understand as opposed to being overly precise [For example, if there

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	are exclusions in a requirement, rather than trying to calculate reserve recovery to the minute, exclude the hour when the situation occurs and the following hour(s), the number of hours determined by the extent contingency reserves were depleted)? The SDT is not sure we understand how you are suggesting we simplify the proposed standard. The SDT has made significant modifications to the requirements which hopefully has addressed your concerns. We agree with comments submitted by the IRC-SRC and MRO-NSRF as applied to the current draft. The question is whether to continue to adjust the current draft or make sure we are creating a solution that is relatively simple to apply and provides reliability value. If we continue down the current path for the standard, we have two primary concerns. Our first concern is that the lowering of the threshold to 900 MW in the East, coupled with the proposed change from quarterly average performance to individual event performance, will increase customer costs for no discernable reduction in reliability risk. Both DCS performance (ALR statistics) and frequency performance (NERC Resources Subcommittee minutes) show frequency performance is more than adequate. As noted by Chairwoman LaFleur at NERC Board meetings, we should consider the reliability benefits of a standard vs. its costs. Costs will increase with the lower threshold for our customers. Because the interconnection is over-biased (ACE overstates resource loss) and dispatchers operate conservatively, our operators will likely deploy set-aside contingency reserves for any loss over 750 MW rather than wait to double-check the event size. (An event is defined by the size of the resource lost, not the change in ACE.) This will likely add scores of contingency reserve deployment cases each year for situations that could likely be met by other on-line reserves. The proposed standard does not require the activation of a specific reserve product, it requires correcting ACE within the specified time period. There is no requirement for any entity to respond in a specific manner.

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	Finally, it should be noted that the frequency change from a 900 MW loss in the East is barely beyond the change from a Time Error Correction. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the East. The SDT does not see the significance in changing from a 900 MW to 1000 MW reporting threshold. The SDT does not believe that the lower threshold will place any undue burden on the reporting of events. The SDT would welcome any information that you could provide to justify the suggested modification. We also recommend that NERC retains the quarterly reporting. Individual cases of non-compliance can be tallied in the form to achieve the FERC directive, but we believe it is important that Enforcement assesses compliance base on the aggregate performance of the BA or RSG, not just spot observations. Our second major concern with the current posting for comment is that R2 goes beyond the original intent of the DCS. The reason there are no measures for this requirement in BAL-002-0 is that it was never intended to be a commodity standard. The predecessor to DCS was Policy 1, which had guidelines on operating reserves. The first DCS was one of NERC's first performance-based standards and existed prior to the ERO. The intent was to retain the concept of the guide to plan to have a certain amount of reserves. The measures of success were to meet CPS and DCS. DCS' intent was to respond quickly to all large events, with performance evaluated on events 80%-100% of MSSC. The intent of the 90 minute reserve replenishment was to get ready for future events (meaning you'd be held for compliance to the standard for events 90 minutes thereafter). Another reason for our concern is that this commodity requirement is being proposed without any data to support what actually is carried hour to hour across the Interconnections and the extent operators draw on these reserves to keep their system balanced. If R2 is retained as proposed, we believe that it should be a "positioning" requirement, not a zero-defect requirement. As proposed, either customer costs will increase or reliability will be negatively impacted. The only way to have more than 100% reserves all the time in normal operations is to carry well more than 100% reserves as a basis of operations or choose not to deploy reserves for non-reportable events and draw

Organization	Question 1 Comment
	on frequency bias to keep reserves available. While the proposal provides some exclusions, the requirement should start on the basis that there will always be some variability and unforeseen non-consequential events that will require reserve deployment. If retained, we suggest R2 should require contingency reserves > 100% MSSC for 99% of all applicable hours. It should be noted that just because a BA has less than MSSC in one hour in four days, does not mean that it had zero reserves in that hour. Additionally, in a multi-BA Interconnection, the odds that the Interconnection would be deficient in Reserves with a 99% BA standard are astronomical. In a single-BA Interconnection there are backstops in the EOP and IRO standards. BAL standards are for normal operations. Other standards protect against events > N-1. Finally, we believe there should be a single quarterly report for R1 and R2. The R1 portion should be simplified to be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of non-excluded hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. Individual event reporting versus quarterly reporting includes the following points: 1. The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950) 2. Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity's failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability.

Organization	Question 1 Comment
	If we assume that the total response provided in the quarter divided by the total response required in the quarter, only the MWs failed to be delivered matters, not the amount of time afterwards. Therefore, an individual event evaluation provides for a much better means to determine the impact to reliability from a single failure as opposed to a quarterly mishmash of all events. The drafting team believes that while a quarterly report may provide good data for trend analysis, it is a poor means to determine compliance. The individual event reporting moves the compliance process to meet the already used enforcement process. This also satisfies a FERC Order 693 directive. From Order 693 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.
MRO-NERC Standards Review Forum	We commend the drafting team on the improvements made since the last posting. Below are our concerns and recommendations for improvement. The NSRF is concerned that the lowering of the threshold to 900 MW for the Reportable Balancing Contingency Event in the Eastern Interconnection, coupled with the proposed change from quarterly average performance to individual event performance will increase customer costs and significantly increase compliance exposure for no difference in reliability risk. Because the interconnection is over-biased (ACE overstates resource loss) and operators operate conservatively, they will likely deploy contingency reserves for any loss over 800 MW. Our recommendation is that the standard uses the lesser of 80% of MSSC or 1000 MW for the Eastern Interconnection. The SDT does not see the significance in changing from a 900 MW to 1000 MW reporting threshold. The SDT does not believe that the lower threshold will place any undue burden

Organization	Question 1 Comment
	on the reporting of events. The SDT would welcome any information that you could provide to justify the suggested modification. Don’t Change from Present Quarterly Reporting: We have fundamental concerns with changing the current quarterly reporting to exception reporting. We can find no directive for this change which increases compliance exposure and will have unintended consequences in how Reserve Sharing Groups (RSG) will operate. A failure of a contingency resource to start or start a minute late can cause performance that has a very low score for that single event, even though recovery is only a minute late or two late. There are RSGs that mitigate this compliance risk by deploying reserves for much smaller events, which helps reliability by quickly recovering from smaller events and replenishing these reserves as well as giving operators repeated practice in reserve deployment. Since each and every event is individually sanctionable, these RSGs will quickly change their rules to raise their reportable threshold to the interconnection minimum. Exception reporting will also eliminate a data source that is used for NERC’s RAPA group and the State of Reliability Report: http://www.nerc.com/pa/RAPA/ri/Pages/DCSEvents.aspx, which is another step backward. We believe there should be a single quarterly report for R1 and R2. The R1 portion would be very similar to today, to include reporting of events > MSSC (but not part of compliance evaluation). The quarterly R2 portion of the report should have the number of hours the BA had reserves < MSSC and an identifier which hours were excludable under 2.1 through 2.6. . The VSLs should be based on the number of hours that reserves were < MSSC and not excluded: o Low: 2 or fewer hours (represents 0.09% of the hours in the quarter) o Medium: 3-5 hours o High: 6-9 hours o Severe: 10 or more hours (10 hours represents 0.5% of the hours in a month) NERC is trying to move away from zero defect standards. This standard should be structured to support that concept.

<table>
<tr><th>Organization</th><th>Question 1 Comment</th></tr>
<tr><td></td><td>
The reporting approach need not hard coded in requirements, but could be compliance section of the standard.
Individual event reporting versus quarterly reporting includes the following points:

The minimum requirement for compliance is 100 percent so any failure to respond causes a non-compliance. The question then is how is a fine determined? Should it be based on the percentage of events for which compliance was/was not obtained, the percentage of failed response (i.e. total response needed for all events was 1,000, response received was 950)
Quarterly reporting averages can move based on the number of reportable events in a quarter, the size of reportable events or other variable that arguable have no bearing on the impact to the BES of an entity's failure to meet the response requirement. Depending on the answer to the first issue, this may or may not be a reasonable metric. Just because it has been used for compliance purposes, that does not mean it is a reasonable measure of reliability or impact to reliability.

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Organization	Question 1 Comment
	position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters We also had comments on a few specific items in R1. Our suggested wording changes are in [ ]. ***1.2. A Responsible Entity is not subject to compliance with Requirement R1 when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated [or depleted]. ***Contingencies can happen that take away reserves without the reserves being activated. And if these contingencies aren't "sudden", then it appears there is no acknowledgment of the reserve loss under the standard. ***(ii) after multiple Balancing Contingency Events for which the combined [capacity] magnitude exceeds the Responsible Entity's Most Severe Single Contingency for those events that occur within a 105-minute period. ***Contingencies of partially loaded generators remove not only MW from the BA, but the reserves they had as headroom. It is possible to have multiple contingencies where the MW loss is < MSSC, but reserves that were lost completely deplete the BA of its contingency reserves. There should be clarification that the magnitude loss is based on capacity, not MW loss. The SDT has made significant modifications to Requirement R1.

END OF REPORT

Standard Development Timeline

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

Description of Current Draft

(Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with parallel ballot, 45-day formal comment period with parallel additional ballot, final ballot.)

Completed Actions	Date
The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal industry comment period.	May 15, 2007
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Anticipated Actions	Date
45-day formal comment period with parallel additional ballot	June/July 2015
Final ballot	July 2015
NERC Board adoption	August 2015

New or Modified Terms Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
    a. Due to
        i. unit tripping,
        ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
        iii. sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW

- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Rationale for Contingency Reserve Definition: Originally a waiver of the R3 Contingency Reserve Restoration requirement was proposed in the event of an Energy Emergency Alert (EEA). This was predicated on a definition of Contingency Reserve that did not include readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA and on concern that the attempt to restore Contingency Reserve during an EEA could well result in actual curtailment of Firm Demand in order to free up generation not to be used but merely to be counted as restored Contingency Reserve when no other Balancing Contingency Event arose. As an alternative to waiving R3, and to remedy the concern, readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA was proposed for inclusion in the definition of Contingency Reserve as it would make Firm Demand merely ready to be curtailed in case another Contingency arose during an EEA.

Readiness to reduce Firm Demand here is a way of providing Contingency Reserves exclusively when the Responsible Entity is in a Contingency Reserve Restoration Period during an emergency. Readiness means the RE is prepared to reduce Firm Demand to mitigate events which may increase demand or reduce supply causing unacceptable risk. The RE should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event.

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

    4.1. Responsible Entity

    4.1.1. Balancing Authority

    4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

    4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-2.
6. **Background:**

    Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity is:

- experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

Rationale for Requirement R2: R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

Rationale for Requirement R3: This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Real-time Operations**	**Medium**	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	**Operations Planning**	**Medium**	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the

			greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain the Operating Process.		Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	Responsible Entity's Most Severe Single Contingency..
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

Rationale

Upon Board approval, the text from the rationale boxes will be moved to this section.

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Description of Current Draft

(Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with parallel ballot, 45-day formal comment period with parallel additional ballot, final ballot.)

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This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by ~~less than~~ one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit~~Unit~~ tripping,
      ii. loss~~Loss~~ of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System~~electric system~~, or
      iii. sudden~~Sudden~~ unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to unplanned~~forced~~ outage of transmission equipment that causes an unexpected imbalance between generation and Demand~~load~~ on the Interconnection.

C. Sudden restoration of a Demand~~load~~ that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the ~~Reserve Sharing Group (~~RSG~~)~~ or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand~~firm system load~~ and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results~~resulting~~ in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection.~~, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan~~

~~rate data.~~ Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins~~beginning~~ at the time that the resource output begins to decline within the first one-minute interval of~~that defines~~ a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Rationale for Contingency Reserve Definition: Originally a waiver of the R3 Contingency Reserve Restoration requirement was proposed in the event of an Energy Emergency Alert (EEA). This was predicated on a definition of Contingency Reserve that did not include readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA and on concern that the attempt to restore Contingency Reserve during an EEA could well result in actual curtailment of Firm Demand in order to free up generation not to be used but merely to be counted as restored Contingency Reserve when no other Balancing Contingency Event arose. As an alternative to waiving R3, and to remedy the concern, readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA was proposed for inclusion in the definition of Contingency Reserve as it would make Firm Demand merely ready to be curtailed in case another Contingency arose during an EEA.

Readiness to reduce Firm Demand here is a way of providing Contingency Reserves exclusively when the Responsible Entity is in a Contingency Reserve Restoration Period during an emergency. Readiness means the RE is prepared to reduce Firm Demand to mitigate events which may increase demand or reduce supply causing unacceptable risk. The RE should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event.

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan~~The capacity may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation~~.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-2. ~~**Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~
6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance).~~.~~ Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting~~Reportable~~ Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand~~load~~ while managing reliability. The~~Also, the~~ SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall~~, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of~~: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- ~~Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i)~~

~~beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,~~

~~or,~~

~~Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.~~

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

~~**1.1.**~~**1.2.** document all~~All~~ Reportable Balancing Contingency Events ~~will be documented~~ using CR Form 1.

~~**1.2.**~~**1.3.** deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is ~~A Responsible Entity is~~ not subject to compliance with Requirement R1 part 1.1 if:~~when it is experiencing a Reliability Coordinator approved Energy Emergency Alert Level under which Contingency Reserves have been activated.~~

- the Responsible Entity is:
  - experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
  - utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
  - the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:~~Requirement R1 (in its entirety) does not apply:~~

- multiple Contingencies where~~(i) when~~ the combined MW loss ~~Responsible Entity experiences a Balancing Contingency Event that~~ exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- ~~(ii) after~~ multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose~~for which the~~ combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency ~~for those events that occur within a 105-minute period~~.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, ~~or~~then dated documentation that demonstrates compliance with Requirement R1 part~~1.2 and~~ 1.3 must also be provided.

Rationale for Requirement R2: R2 establishes ~~a uniform continent-wide contingency reserve requirement. R2 establishes a requirement that contingency reserve be at least equal to~~ the need to actively plan in ~~applicable entity's Most Severe Single Contingency. By including a definition of Most Severe Single Contingency and R2, a consistent uniform continent-wide contingency reserve requirement has been established. Its goal is to assure that~~ the near term (e.g., day-ahead) for expected~~Responsible Entity will have sufficient contingency reserve that can be deployed to meet R1.~~

~~FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a~~ Reportable Balancing Contingency Events. This requirement is similar to the current standard~~Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003,~~ which requires an entity to have available a level of ~~addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide~~ contingency reserves equal to ~~policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.~~

~~In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the amount of its Contingency Reserve available and whether it has sufficient response. Additionally, the drafting team understands that the Responsible Entity's available Contingency Reserve may vary slightly from MSSC at any time. This variability is recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.~~

~~The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying operators' hands by removing use of their available contingency reserve from their toolbox in order to maintain service to load~~ or greater~~manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in Real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for issues other~~ than its Most Severe Single Contingency. ~~a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve.~~

R2. Each~~The~~ Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of ~~Contingency Reserve, averaged over each Clock Hour, greater than or equal to~~ its Operating Plan to determine its~~average Clock Hour~~ Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than ~~, except during one or more of the following periods when~~ the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.~~Entity is:~~ *[Violation Risk Factor: Medium] [Time Horizon: ~~Real-time~~ Operations Planning]*

~~2.1 using its Contingency Reserve, for a period not to exceed 90 minutes, to mitigate the reliability concerns associated with Contingencies that are not Balancing Contingency Events; and/or~~

~~2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or~~

~~2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or~~

~~2.4 in a Contingency Reserve Restoration Period; and/or~~

~~2.5 in a Contingency Event Recovery Period; and/or~~

~~2.6 in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared.~~

M2. Each Responsible Entity will~~shall~~ have the following ~~dated~~ documentation to show~~that demonstrates~~ compliance with Requirement R2:

M2.1 a dated Operating Process;

M2.2 evidence to indicate that the Operating Process has been reviewed~~. Evidence of compliance may include, but is not limited to, documenting Contingencies~~ and maintained annually; and,

~~**M2.**~~ evidence such as Operating Plans or other~~Energy Emergency Alert Levels through outage records,~~ operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.~~logs, and others.~~

~~Compliance may be achieved by demonstrating that:~~

~~**M2.1**~~**M2.3** ~~Contingency Reserve, averaged over each Clock Hour, meets or exceeds the required Contingency Reserve; or,~~

- ~~Contingency Reserve has been restored to the required Contingency Reserve levels within the specified period: or,~~
- ~~the sum of the Contingency Reserve and Firm Load available as a substitute for unavailable Contingency Reserve reaches the required Contingency Reserve level within the specified period;~~

~~Any shortfall from compliance will be measured as compliance of 100% minus the shortfall's percentage share of MSSC.~~

~~If the recording of Contingency Reserve or MSSC is interrupted such that more than 50 percent of the samples within the clock hour are invalid data, then that clock hour is excluded from evaluation. If any portion of the Clock Hour is excluded by rule in Requirement R2, then compliance with that portion of the hour not excluded may be shown by either determination of the integrated value for that portion of the hour not excluded by the rule or an instantaneous value showing reserves any time during the excluded period.~~

Rationale for Requirement R3: This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	The Responsible Entity achieved~~recovered~~ less than 100% but at least~~more than~~ 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved~~recovered~~ ~~90% or~~ less than 90% but at least~~more than~~ 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved~~recovered~~ ~~80% or~~ less than 80% but at least~~more than~~ 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved~~recovered~~ ~~70% or~~ less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	~~Real-time~~ Operations Planning	Medium	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have~~had~~ Contingency	N/A~~The Responsible Entity had Contingency Reserve but the Clock Hour average amount of Contingency Reserve was less than 90% of MSSC but was greater than or equal~~	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have~~had~~ Contingency Reserve equal to, or	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to~~did not~~ have Contingency Reserve ~~that was~~

			Reserve equal to, or ~~but the Clock Hour average amount of Contingency Reserve was less than 100% of MSSC but was~~ greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain~~or equal to 90% of MSSC as averaged over~~ the Operating Process~~Clock Hour~~.	~~to 80% of MSSC as averaged over the Clock Hour.~~	~~but the Clock Hour average amount of Contingency Reserve was less than 80% of MSSC but was~~ greater than the Responsible Entity's Most Severe Single Contingency but failed to implement~~or equal to 70% of MSSC as averaged over~~ the Operating Process~~Clock Hour~~.	equal to, or greater than ~~70% of MSSC averaged over~~ the Responsible Entity's Most Severe Single Contingency.. ~~Clock Hour.~~
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
2		NERC BOT Adoption	Complete revision

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

Rationale

Upon Board approval, the text from the rationale boxes will be moved to this section.

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group

(RSG) or a Balancing Authority's area that is not part of a Res area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The existing definition of Contingency Reserve should be retired at midnight of the day immediately prior to the effective date of BAL-002-2, in the jurisdiction in which the new standard is becoming effective.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

> The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan

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

Implementation Plan for BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Approvals Required

BAL-002-2 – Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by ~~less than~~ one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit~~Unit~~ tripping, or
      ii. loss~~Loss~~ of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System~~electric system~~, or
      iii. sudden~~Sudden~~ unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand~~load~~ on the Interconnection.
C. Sudden restoration of a Demand~~load~~ that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Res area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG~~Reserve Sharing Group (RSG)~~ or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand~~firm system load~~ and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results~~resulting~~ in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection.~~, and occurring within a one-minute interval of the initial sudden decline in ACE based on EMS scan rate data.~~ Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins~~beginning~~ at the time that the resource output begins to decline within the first one-minute interval of~~that defines~~ a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy

Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:~~The capacity may be provided by resources such as Demand-Side Management (DSM), Interruptible Load and unloaded generation.~~

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The existing definition of Contingency Reserve should be retired at midnight of the day immediately prior to the effective date of BAL-002-2, in the jurisdiction in which the new standard is becoming effective.

Applicable Entities

Balancing Authority

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective as follows:

The first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

BAL-002-0, Disturbance Control Performance, and BAL-002-1, Disturbance Control Performance should be retired at midnight of the day immediately prior to the Effective Date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Unofficial Comment Form

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Do not use this form for submitting comments. Use the electronic form to submit comments on the proposed revisions to **BAL-002-2 Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event**. The electronic form must be submitted **by 8 p.m. Eastern, Thursday, August 20, 2015.**

Documents and information about this project are available on the project page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background Information

Since loss of generation occurrences so often impacts all Balancing Authorities throughout an Interconnection, BAL-002 was created to specify recovery actions and time frames. The original Standards Authorization Request (SAR) approved by the Industry presumes there is presently sufficient contingency reserve in all the North American Interconnections. The underlying goal of the SAR was to update the Standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group such that the parties would better understand the use of contingency reserve to balance resources and demand following a Reportable Contingency Event. The primary objective of BAL-002-2 is to measure the success of recovering from contingency events.

Based on comments received from industry stakeholders the drafting team made the following modifications to the draft standard:

- Modified Requirement R1 to provide additional clarity.
- Modified Requirement R2 to provide for development of a process for Contingency Reserve to be included in an entity’s Operating Plan.
- Added Requirement R3 to provide for the restoration of Contingency Reserve.
- Modified the rationale supporting Requirements R1 and R2 to provide additional information.
- Added rationale to support Requirement R3.
- Added rationale to support the modifications made to the definition of Contingency Reserve.
- Modified the BAL-002-2 Background Document to provide additional clarity.

Questions

1. **Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.**

   Comments:

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Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple a methodology to adequately address all of these interactions. The suite of NERC Standards work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity’s MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002),

this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert.

For additional technical justification for exemption from R1 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity is:

- experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance.

In addition, the standard drafting team (SDT) through R1 Part 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:
    - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.

- o If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:

  - ▪ If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - ▪ If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - ▪ If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

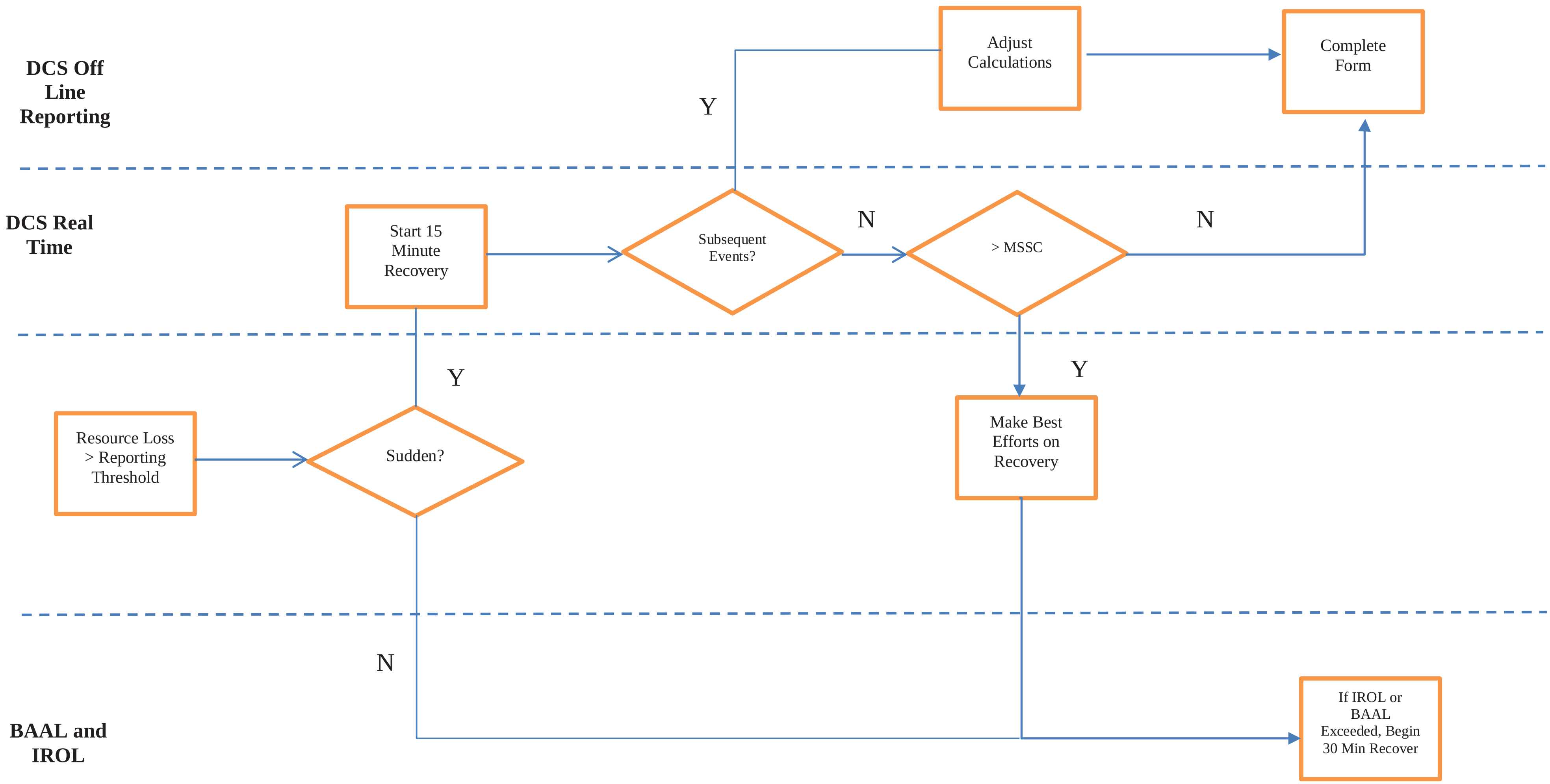
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve be at least equal to the applicable entity's Most Severe Single Contingency and a definition of Most Severe Single Contingency. Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, Requirement R3 addresses restoration of the reserves.

Requirement 3

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events. This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes.

Attachment 1

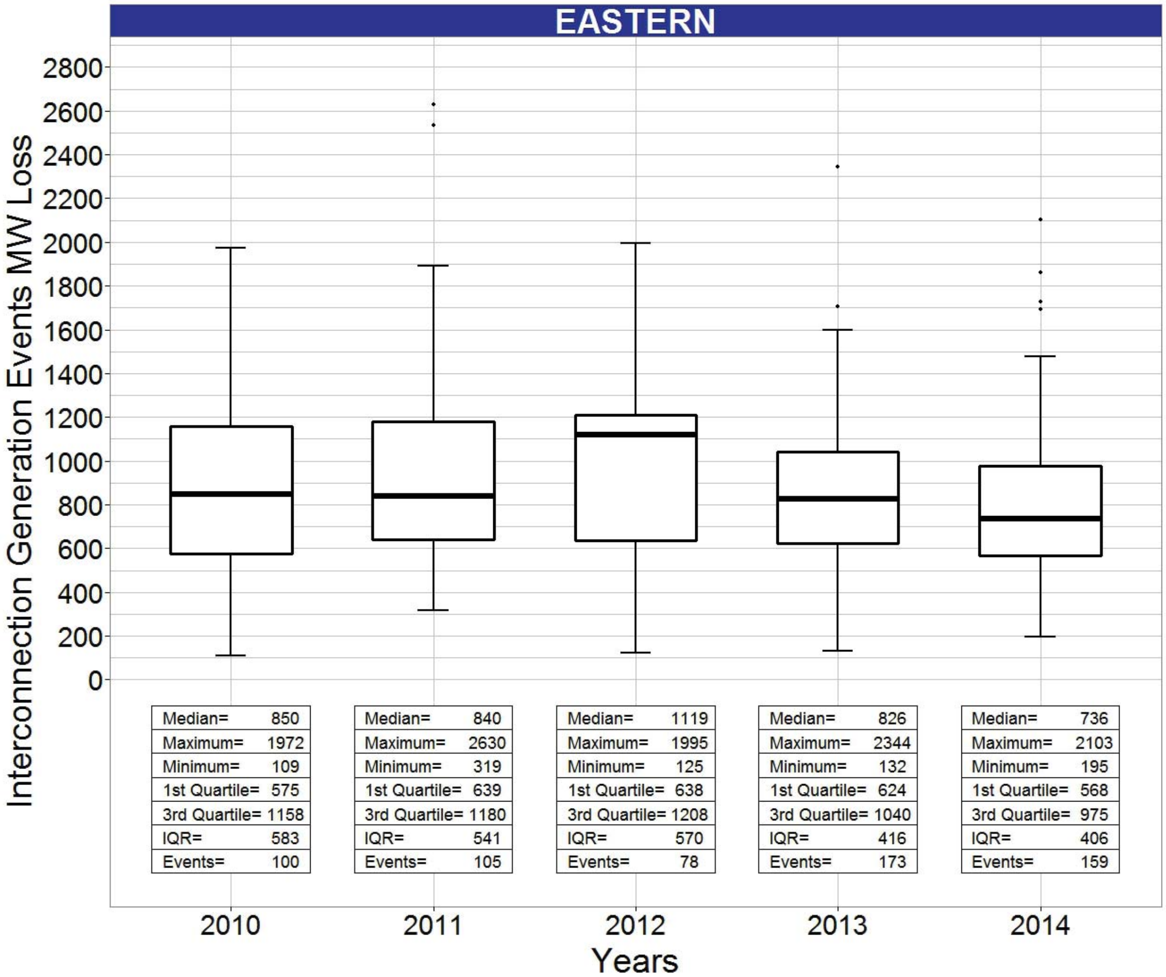
NERC Interconnections 2009-2013

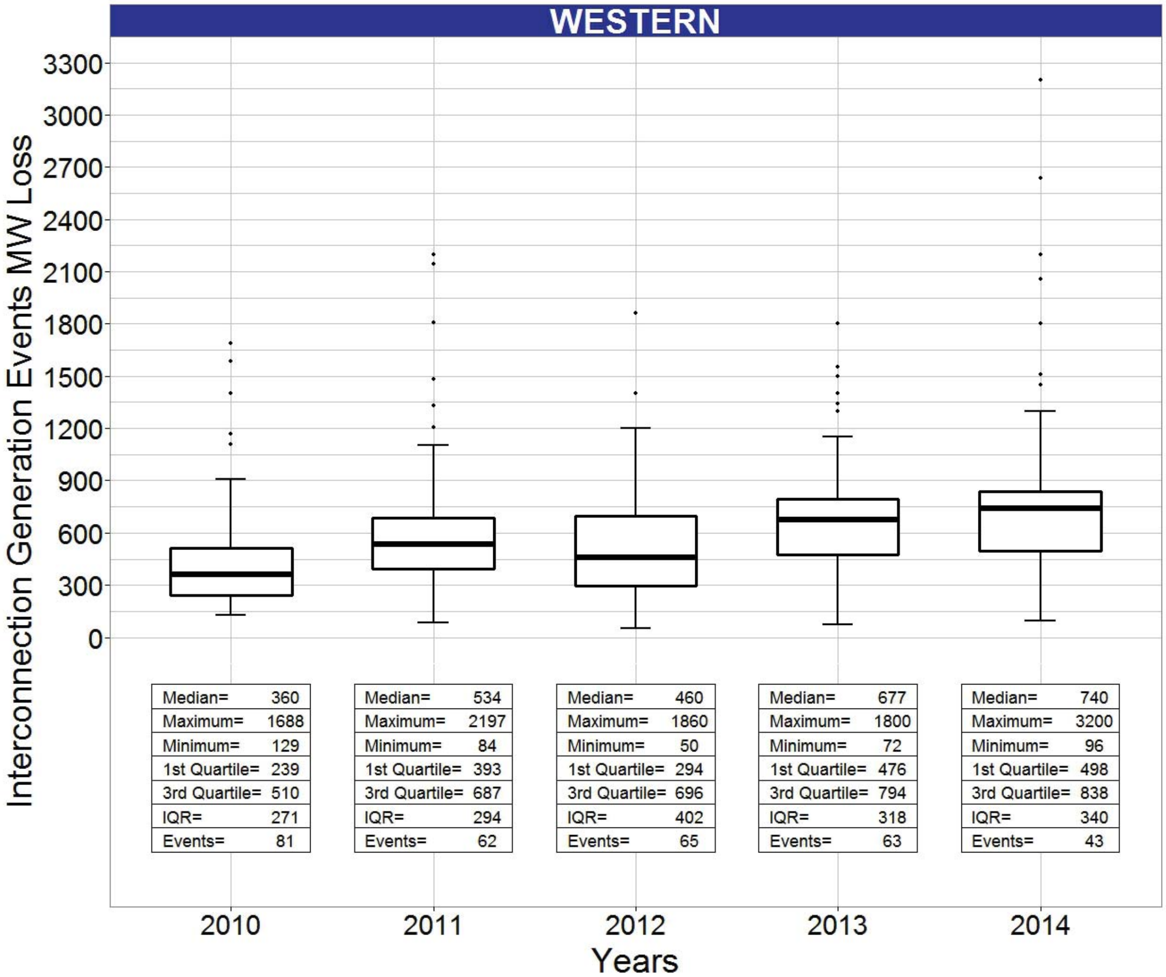
Frequency Events Loss MW Statistics

For: NERC BARC Standard Drafting Team

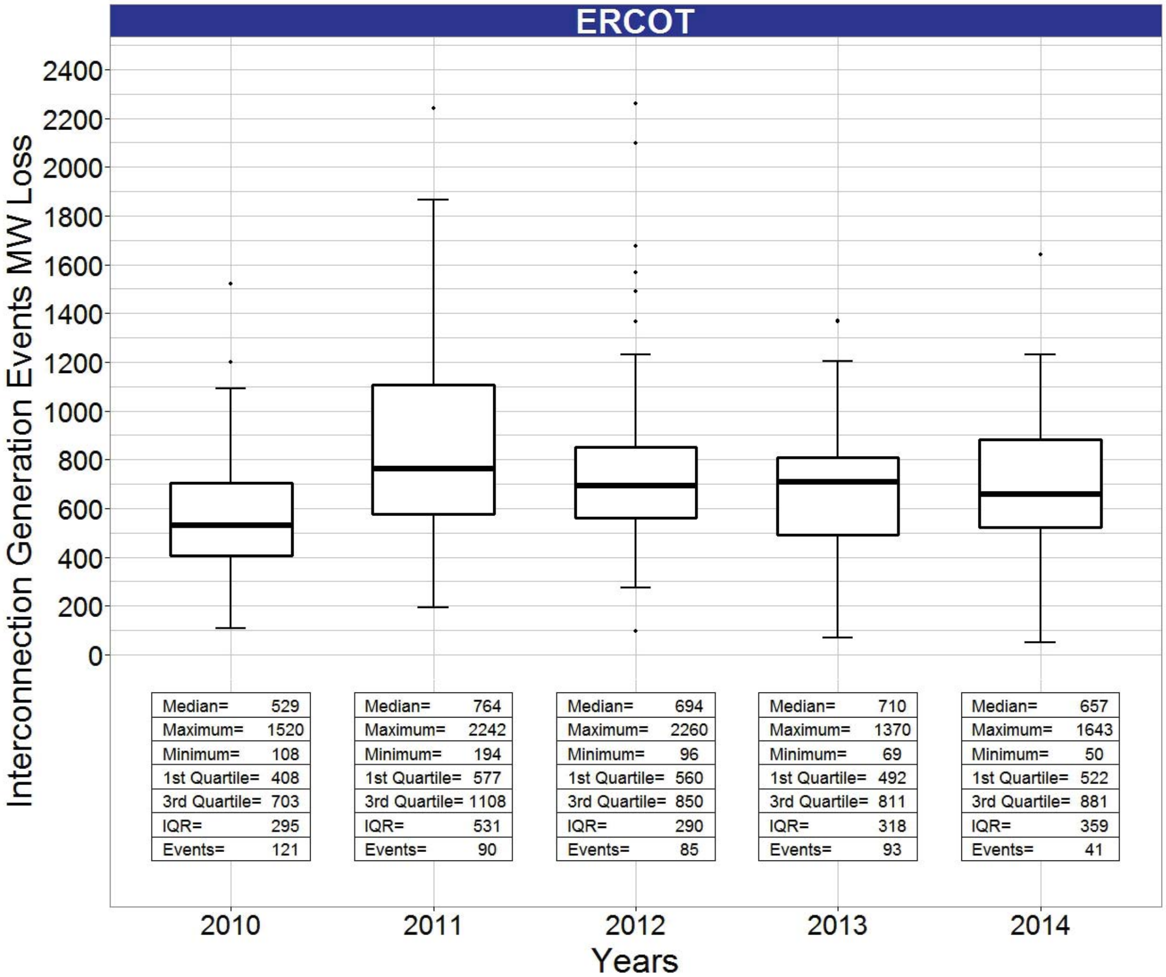
Prepared by: CERTS

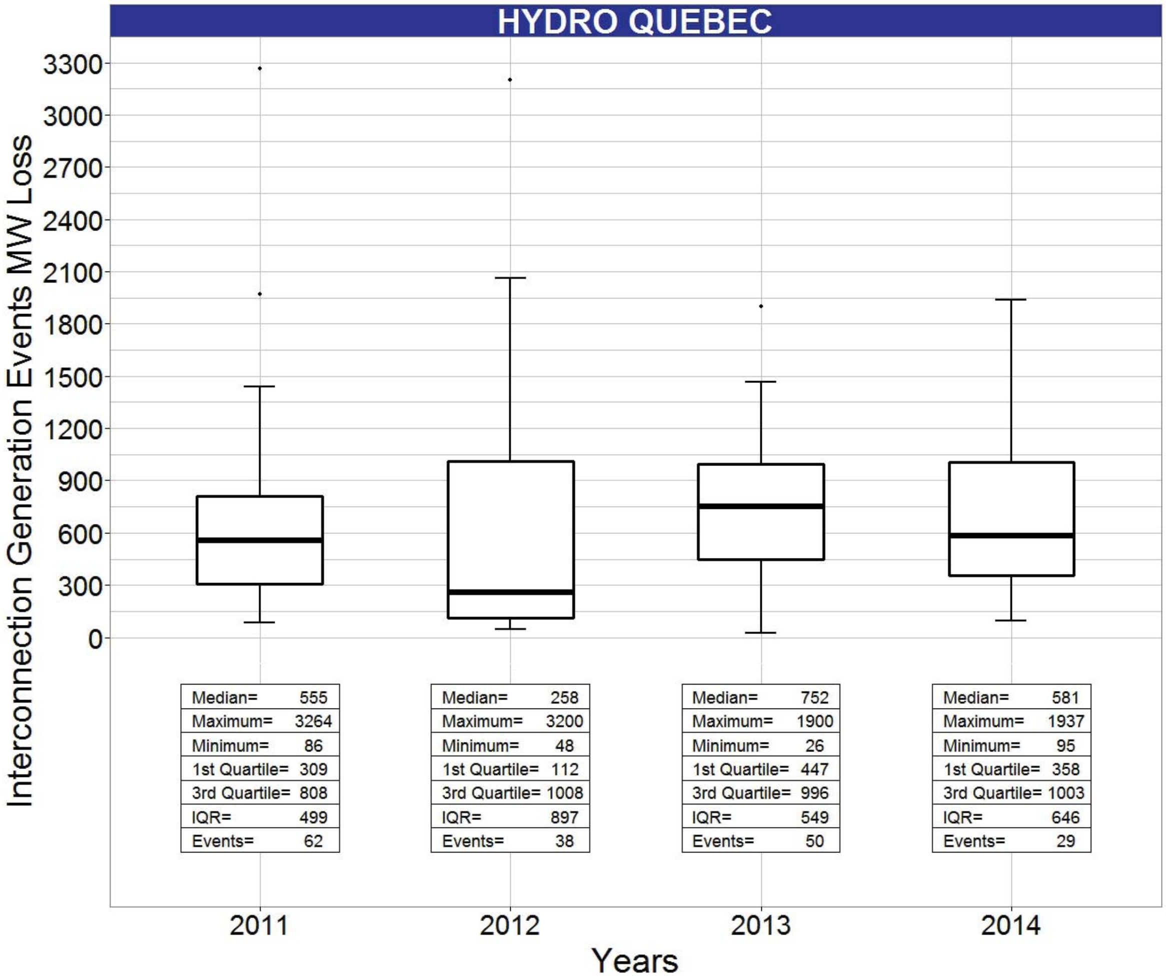
Date: October 15, 2013


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years



	2010	2011	2012	2013	2014
Median=	360	534	460	677	740
Maximum=	1688	2197	1860	1800	3200
Minimum=	129	84	50	72	96
1st Quartile=	239	393	294	476	498
3rd Quartile=	510	687	696	794	838
IQR=	271	294	402	318	340
Events=	81	62	65	63	43


ERCOT
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Interconnection Generation Events MW Loss
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: “Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated.”

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

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4 Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

5 Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

6 Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

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[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.

- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.

- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

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Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's~~Interconnection~~ operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple ~~of~~ a methodology to adequately address all of these interactions. The suite of NERC Standards~~Standard~~ work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard~~,~~ (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 ~~only~~ address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were~~have been~~ 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during ~~the~~ real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002),

this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an~~An~~ Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert. ~~without incurring a Balancing Contingency Event. Without incurring a Balancing Contingency Event, a Responsible Entity cannot utilize its Contingency Reserve to the extent it drops below MSSC without violating NERC Standard BAL-002-2. To resolve this conflict, the drafting team elected to allow the Responsible Entity to be exempt from R2 if in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserves available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. Also, to assure the system operator has the necessary flexibility to address the transition from normal operations (BAL-002) into emergency operations (EOP) the drafting team elected to allow the Responsible entity to be exempt from R2 during one or more of the following periods when the Responsible Entity is:~~

- ~~using its Contingency Reserve for Contingencies that are not Balancing Contingency Events;~~
- ~~responding to an Operating Instruction requiring the use of Contingency Reserve;~~
- ~~resolving the exceedance of a System Operating Limit or IROL that requires the use of Contingency Reserve; and,~~
- ~~in a Contingency Event Recovery Period or its subsequent Contingency Reserve Restoration Period.~~

For additional technical justification for exemption~~exempting periods~~ from R1~~R2~~ to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2~~3~~.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. ~~,~~within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero~~Zero~~ (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, ~~during the Contingency Event Recovery Period,~~ any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such~~each~~ individual Balancing Contingency Event,

or,

- its~~Its~~ Pre-Reporting Contingency Event ACE Value~~,~~ (if its Pre-Reporting Contingency Event ACE Value was negative);~~):~~ however, ~~during the Contingency Event Recovery Period,~~ any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such~~each~~ individual Balancing Contingency Event.

1.2. document all~~All~~ Reportable Balancing Contingency Events ~~will be documented~~ using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is ~~1.2. A Responsible Entity is~~ not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity is:

- ~~when it is~~ experiencing a Reliability Coordinator declared~~approved~~ Energy Emergency Alert Level, and ~~under which Contingency Reserves have been activated.~~
- utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

~~1.3 Requirement R1 (in its entirety) does not apply:~~

1.3.2 ~~(i) when~~ the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss ~~a Balancing Contingency Event that~~ exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or ~~, or~~
- ~~(ii) after~~ multiple Balancing Contingency Events within~~for which~~ the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's~~Entity's~~ Most Severe Single Contingency. ~~for those events that occur within that 105 minute period.~~

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes ~~the amount of Contingency Reserve and~~ recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance. ~~The drafting team has included Attachment 2 illustrating an example of the calculation for Requirement R1.~~

In addition, the standard drafting team (SDT) through R1 Part~~Parts 1.2 and~~ 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1~~2~~, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a~~A~~ fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:
    - If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
    - If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

- Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:
  - If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
  - If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
  - If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

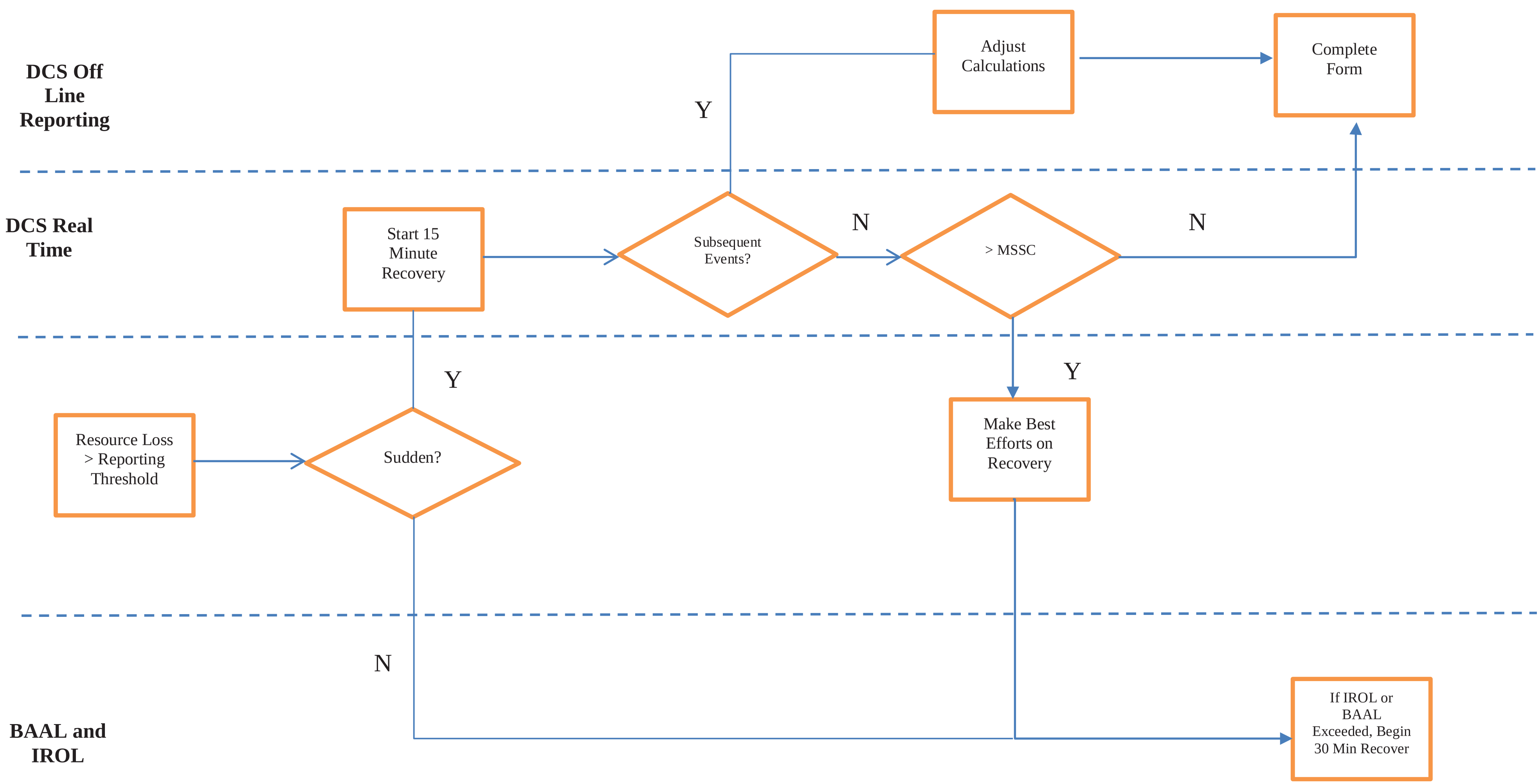
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

Each~~R2. The~~ Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or ~~, averaged over each Clock Hour,~~ greater than ~~or equal to its average Clock Hour Most Severe Single Contingency, except during one or more of the following periods when~~ the Responsible Entity's Most Severe Single ~~Entity is:~~

~~2.1 using its~~ Contingency available~~Reserve,~~ for maintaining system~~a period not to exceed 90 minutes, to mitigate the~~ reliability~~concerns associated with Contingencies that are not Balancing Contingency Events; and/or~~

~~2.2 using its Contingency Reserve, for a period not to exceed 90 minutes, to respond to an Operating Instruction requiring the use of Contingency Reserve; and/or~~

~~2.3 using its Contingency Reserve for a period not to exceed 90 minutes, to resolve the exceedance of a System Operating Limit (SOL) or Interconnection Reliability Operation Limit (IROL) that requires the use of Contingency Reserve; and/or~~

~~2.4 in a Contingency Reserve Restoration Period; and/or~~

~~2.5 in a Contingency Event Recovery Period; and/or~~

R2. ~~in an Energy Emergency Alert Level under which the Responsible Entity no longer has required Contingency Reserve available provided that the Responsible Entity has made preparations for interruption of Firm Load to replace the shortfall of Contingency Reserve to avoid the uncontrolled failure of components or cascading outages of the Interconnection. For this exemption to apply, the preparations must be initiated within 5 minutes from the time that the Energy Emergency Alert Level is declared~~.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of~~requirement. R2 establishes~~ a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve~~contingency reserve~~ be at least equal to the applicable entity's Most Severe Single Contingency and ~~. By including~~ a definition of Most Severe Single Contingency.~~and R2, a consistent uniform continent-wide contingency reserve requirement has been established.~~ Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve~~contingency reserve~~ that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address~~In~~ the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, ~~Violation Severity Levels for~~ Requirement R3 addresses restoration~~R1, the impact~~ of the reserves.

Requirement 3

R3. Each Responsible Entity, following ~~recovering from~~ a Reportable Balancing Contingency Event, shall restore ~~depends on the amount of~~ its Contingency Reserve to at least its Most Severe Single Contingency, before the end of ~~available and whether it has sufficient response. Additionally,~~ the ~~drafting team understands that the Responsible Entity's available~~ Contingency Reserve Restoration Period, but ~~may vary slightly from MSSC at~~ any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events.~~time.~~ This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans~~variability~~ is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes. ~~recognized in Requirement R2 through averaging the available Contingency Reserve over each Clock Hour.~~

~~The ideal goal of maintaining an amount of Contingency Reserve to cover the Most Severe Single Contingency at all times is not necessarily in the best interest of reliability. It may have the unintended result of tying operators' hands by removing use of their available contingency reserve from their toolbox in order to maintain service to load or manage other reliability issues. By allowing for the occasional use of this minimal amount of Contingency Reserve at the operators' discretion for other contingencies, reliability is enhanced. The SDT crafted the proposed standard to encourage the operators to use, at their discretion and within the limits set forth in the standard, their available contingency reserve to best serve reliability in Real-time. The last thing that anyone desires is to have Contingency Reserve held available and the lights go off because the standard would penalize the operator for using the Contingency Reserve to maintain service to the load. However, the drafting team did not believe that the use of reserves for issues other than a Reportable Balancing Contingency Event should be unbounded. The SDT limited the use of Contingency Reserve.~~

Attachment 1

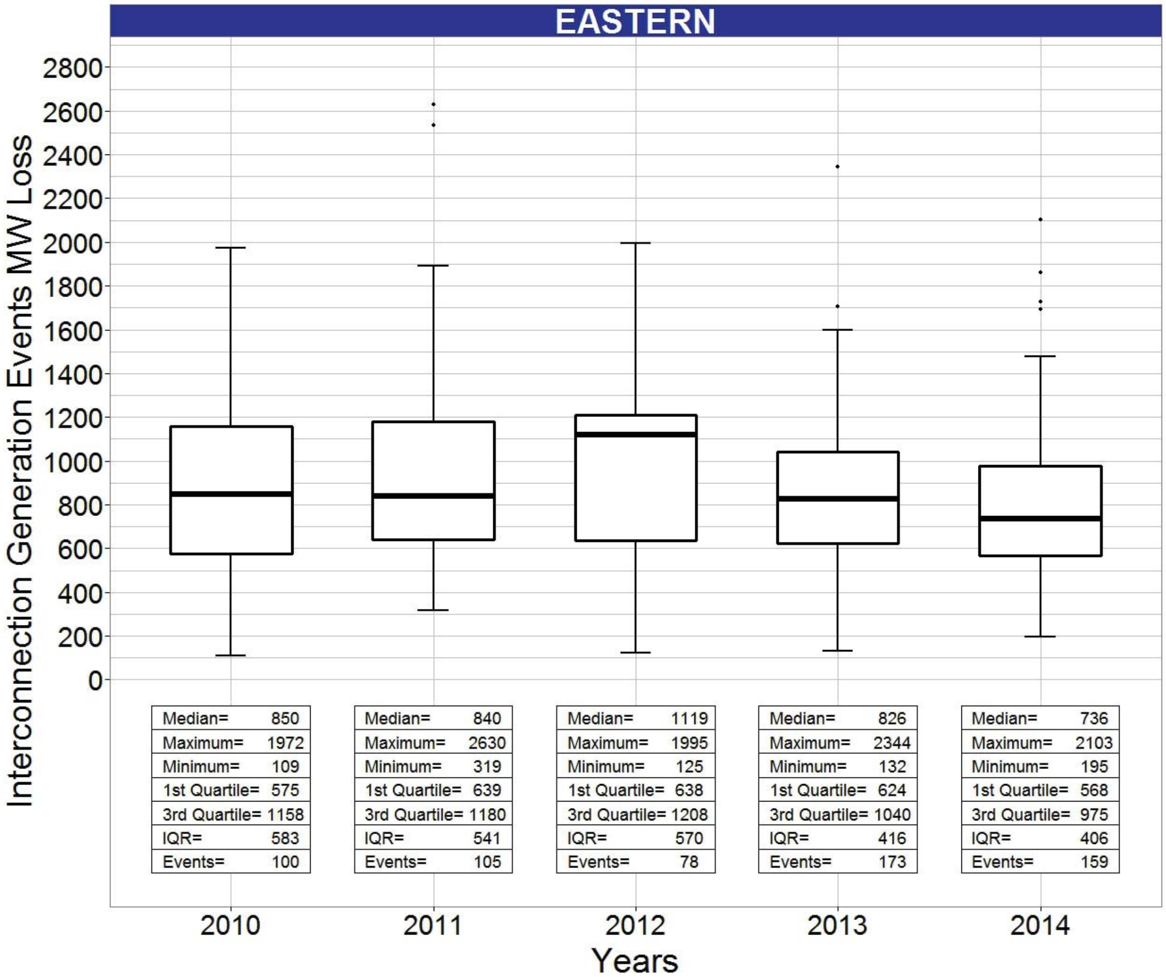
NERC Interconnections 2009-2013

Frequency Events Loss MW Statistics

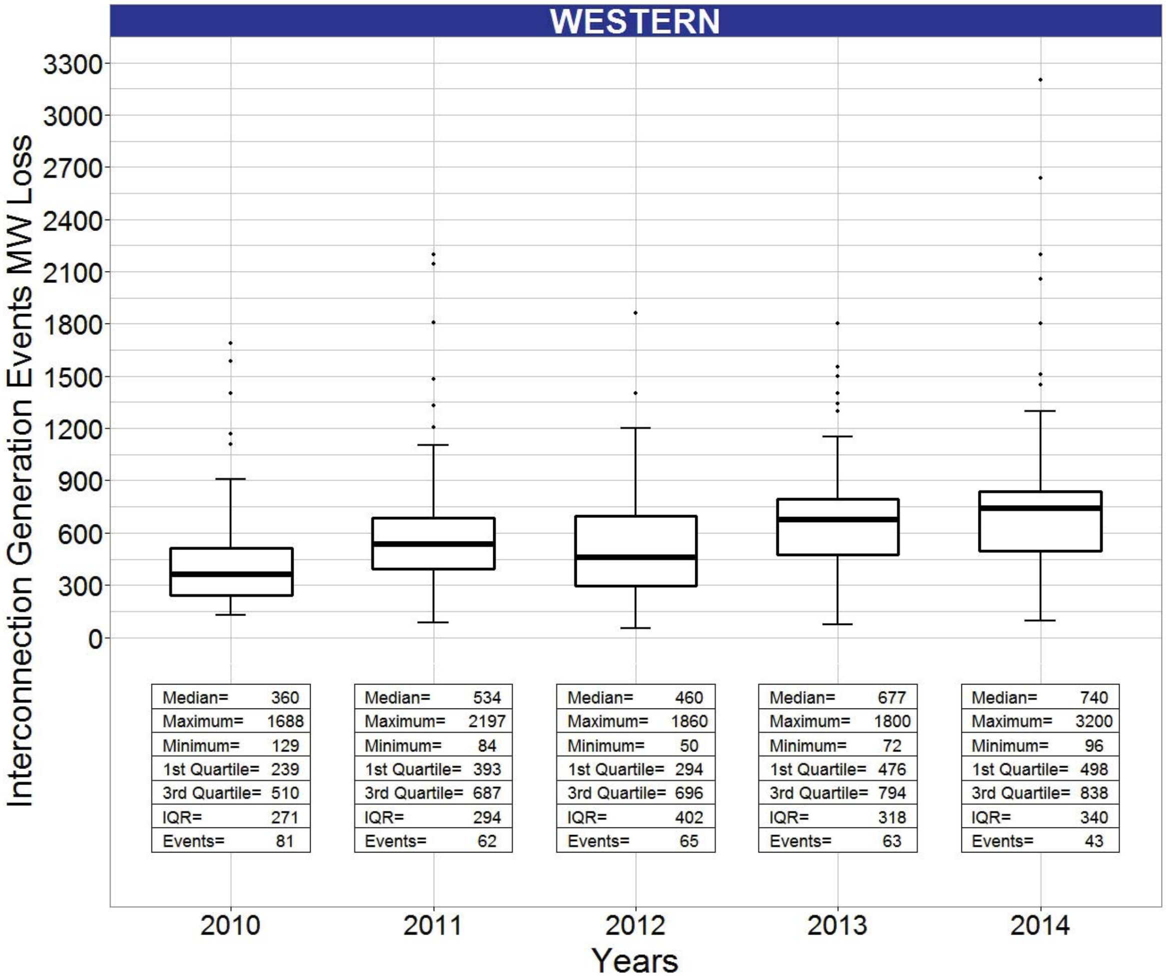
For: NERC BARC Standard Drafting Team

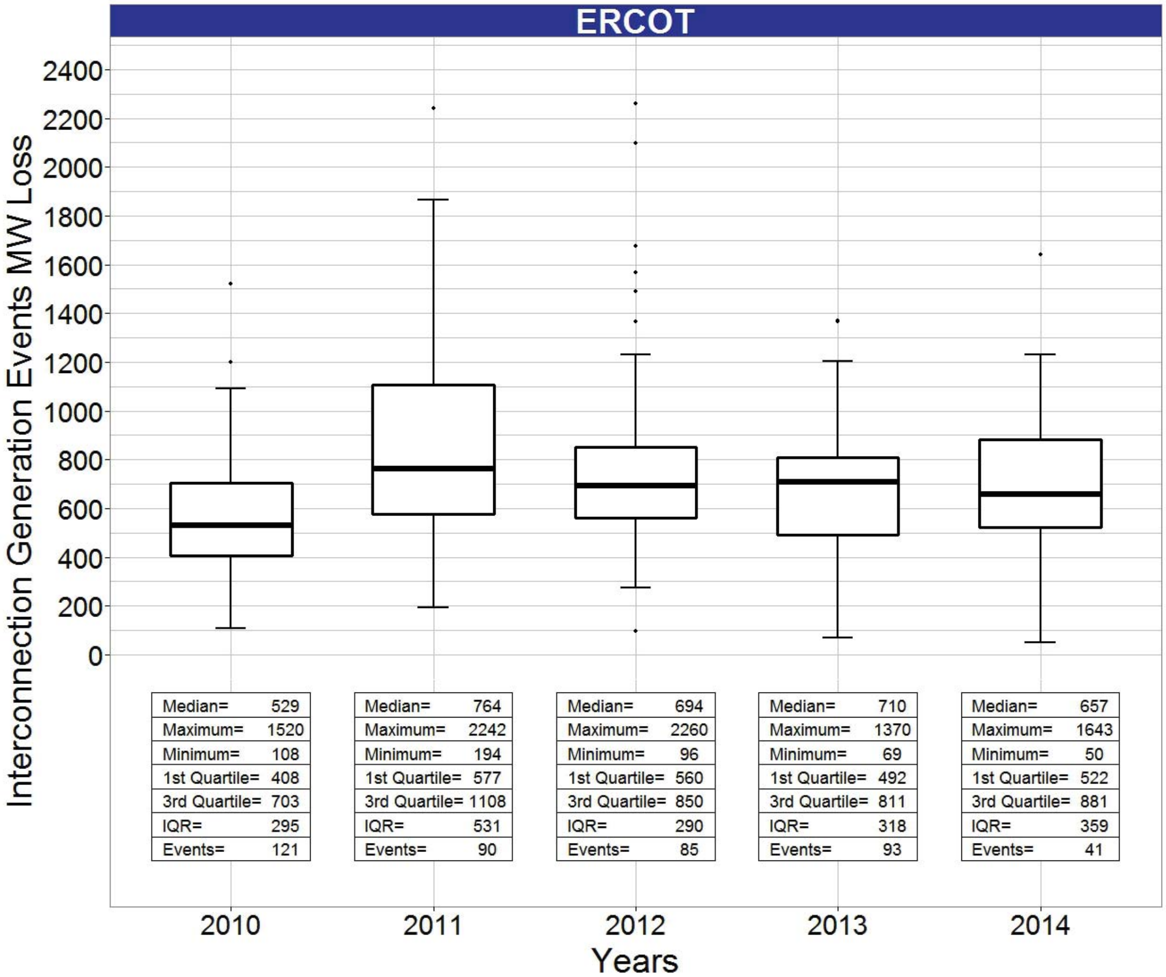
Prepared by: CERTS

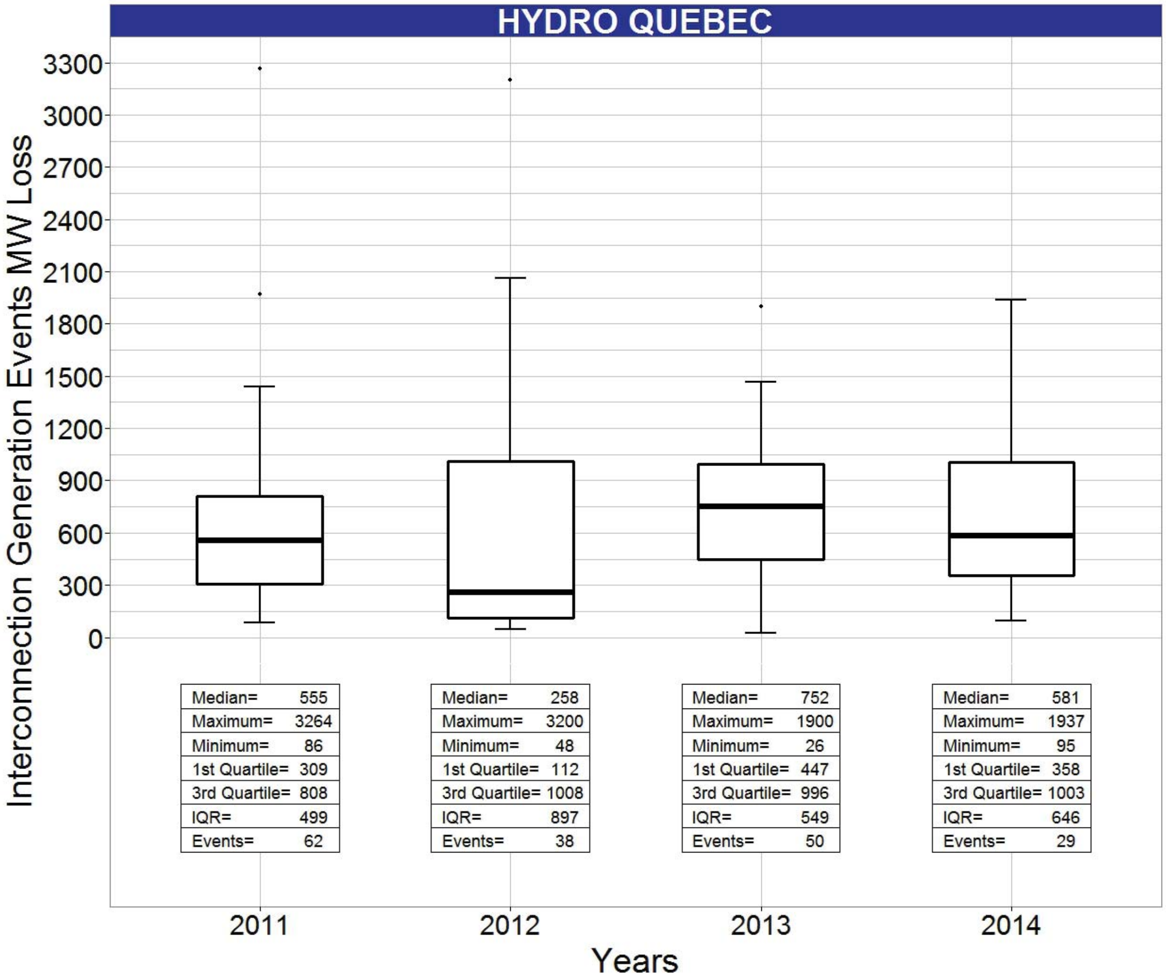
Date: October 15, 2013



	2010	2011	2012	2013	2014
Median=	850	840	1119	826	736
Maximum=	1972	2630	1995	2344	2103
Minimum=	109	319	125	132	195
1st Quartile=	575	639	638	624	568
3rd Quartile=	1158	1180	1208	1040	975
IQR=	583	541	570	416	406
Events=	100	105	78	173	159


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

~~BAL-002-2 R1 Example~~

~~Requirement 1~~

~~The Responsible Entity experiencing a Reportable Balancing Contingency Event shall, within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of: *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations]*~~

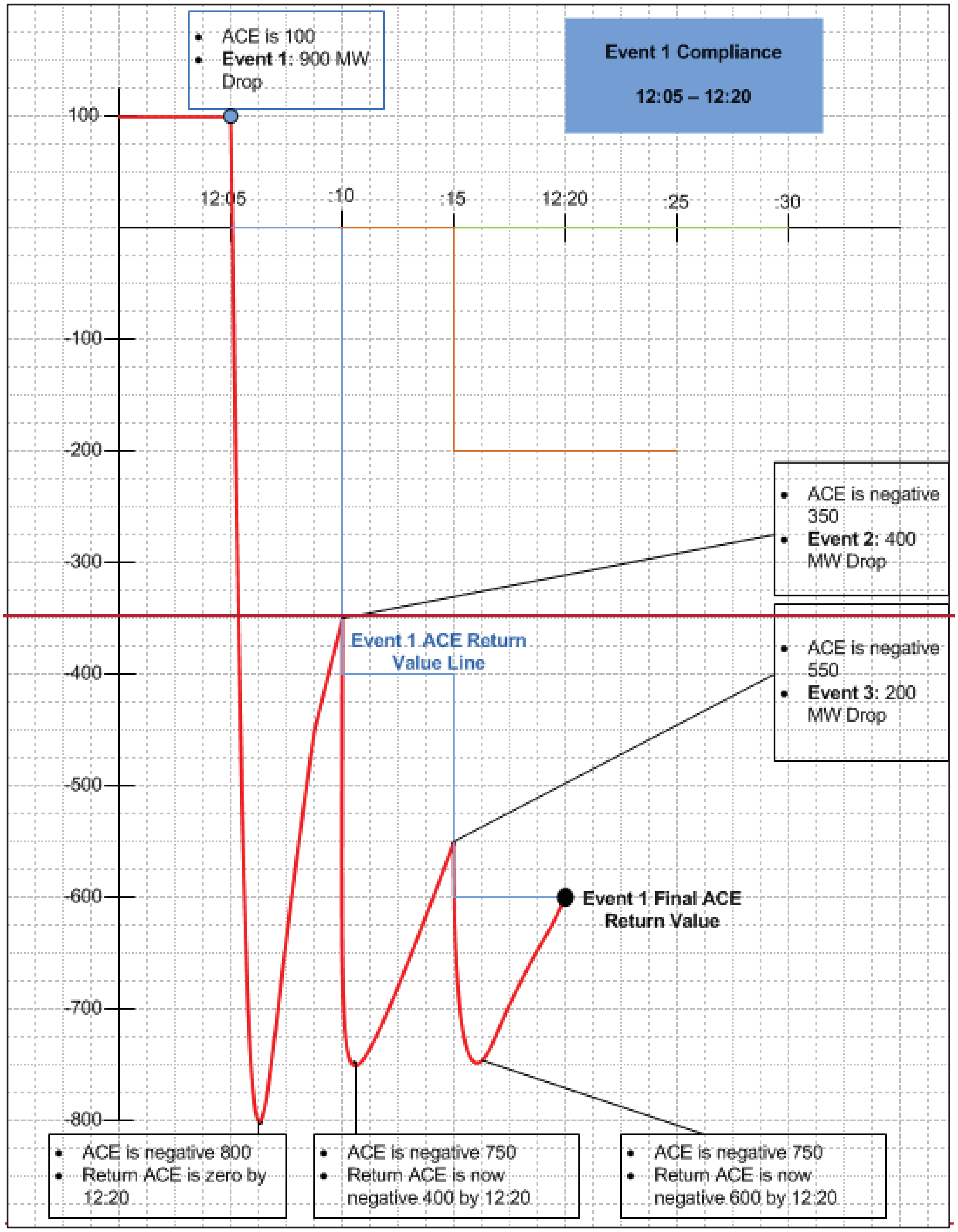
- ~~Zero, (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event,~~

~~Or,~~

- ~~Its Pre-Reporting Contingency Event ACE Value, (if its Pre-Reporting Contingency Event ACE Value was negative); however, during the Contingency Event Recovery Period, any Balancing Contingency Event that occurs shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, each individual Balancing Contingency Event.~~

~~To illustrate the above requirement the following scenario of three Balancing Contingency Events, and compliance for each event, is provided. It is assumed in this scenario that the reportable event threshold is 200 MW.~~

~~Event 1 Compliance~~



- ~~Responsible Entity Pre-Reporting Contingency Event ACE Value is 100 MW~~
- ~~Time of the Balancing Contingency Event - 12:05~~
- ~~Size of the Balancing Contingency Event - 900 MW~~
- ~~Responsible Entity MSSC - 2,000 MW~~

- ~~Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 800 MW~~

~~With no additional Contingency Events, the Responsible Entity must demonstrate recovery of Event 1 by returning its Reporting ACE to at least the recovery value of zero within the Contingency Event Recovery Period, or by 12:20.~~

~~However, if the Responsible Entity experienced another Contingency Event (Event 2) based upon the following:~~

- ~~ACE had recovered to negative 350 – prior to Event 2~~
- ~~Time of the Contingency Event - 12:10~~
- ~~Size of the Contingency Event - 400 MW~~
- ~~Responsible Entity Reporting ACE Value at 12:10 – negative 750~~

~~At the time of Event 2, the Responsible Entity would reduce the value of its required recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2), thus lowering the required recovery value of ACE to negative 400 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Event 2, by returning its Reporting ACE to at least a negative 400 MW by 12:20.~~

~~Now if the Responsible Entity experienced an additional Contingency event (Event 3) prior to 12:20 namely:~~

- ~~ACE had recovered to negative 550 MW – prior to Event 3~~
- ~~Time of the Contingency Event - 12:15~~
- ~~Size of the Contingency Event - 200 MW~~
- ~~Responsible Entity Reporting ACE Value at 12:15 – negative 750~~

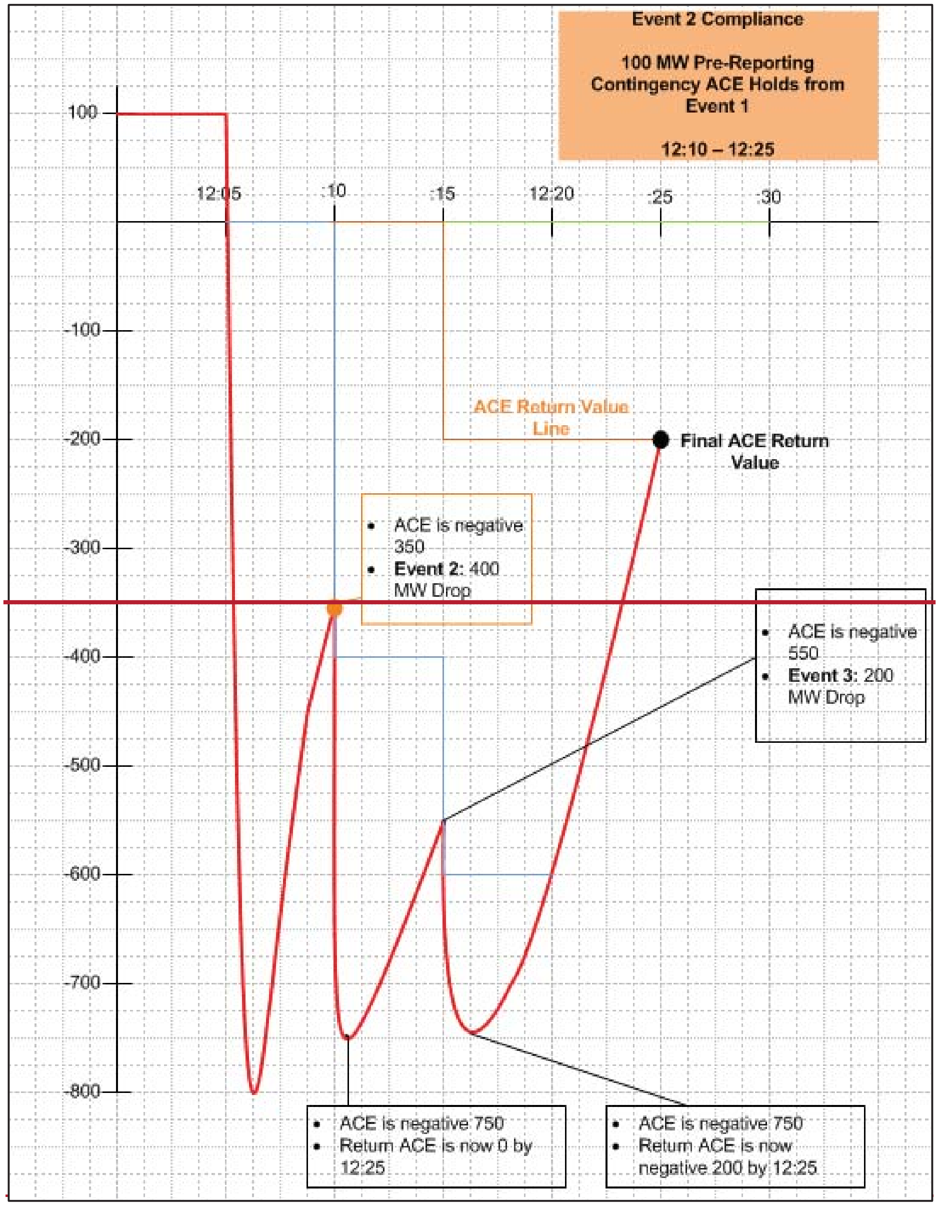
~~At the time of Event 3, the Responsible Entity would reduce the value of its required ACE recovery from the original Balancing Contingency Event 1 by the size of the Contingency Event at 12:10 (Event 2) and the Contingency Event at 12:15 (Event 3), thus lowering the required ACE recovery value to negative 600 MW. The Responsible Entity would demonstrate recovery from Balancing Contingency Event 1, taking into account Events 2 and 3 by returning its Reporting ACE to at least a negative 600 MW by 12:20.~~

~~The Responsible Entity must show compliance for all events that might occur during the Contingency Event Recovery Period (Event 1). Event 2 and Event 3 from the example above would demonstrate compliance in a similar fashion as was demonstrated for Event 1 above. Each would have its own unique Contingency Event Recovery Period as defined by the start of the respective contingency event (i.e. Event 2's Contingency Event Recovery Period would begin at 12:10 and end at 12:25; Event 3's Contingency Event Recovery Period would begin at 12:15 and end at 12:30). The required ACE Value (0 MW) of recovery from Events 1; the required ACE Value (-200 MW) of Recovery from Event 2 would be the required Value (0 MW) of~~

~~Recovery from final Event 3) minus the size of Event 3 (200 MW), while the required ACE Value (-600 MW) of Recovery from Event 1 would be the required Value (0MW) of Recovery from final Event 3 minus the size (600 MW) of the events 2 (400 MW) & 3 (200 MW) subsequent to Event 1.~~

~~The following demonstrates the logic used for compliance with Event 2 (from 12:10 – 12:25, including Event 3).~~

~~**Event 2 Compliance**~~



~~Responsible Entity's required ACE Value of recovery from Event 2 is 0 MW (the same as it was from the pre-existing initial Contingency Event 1 prior to any adjustment for Event 2)~~

- ~~Time of the Balancing Contingency Event - 12:10~~
- ~~Size of the Balancing Contingency Event - 400 MW~~
- ~~Responsible Entity MSSC - 2,000 MW~~
- ~~Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW~~

~~With no additional Contingency Events, the Responsible Entity must demonstrate recovery from Event 2 by returning its Reporting ACE to Event 1's prior, unadjusted Pre-Reporting Contingency Event ACE value of 0 MW within the Contingency Event Recovery Period, or by 12:25.~~

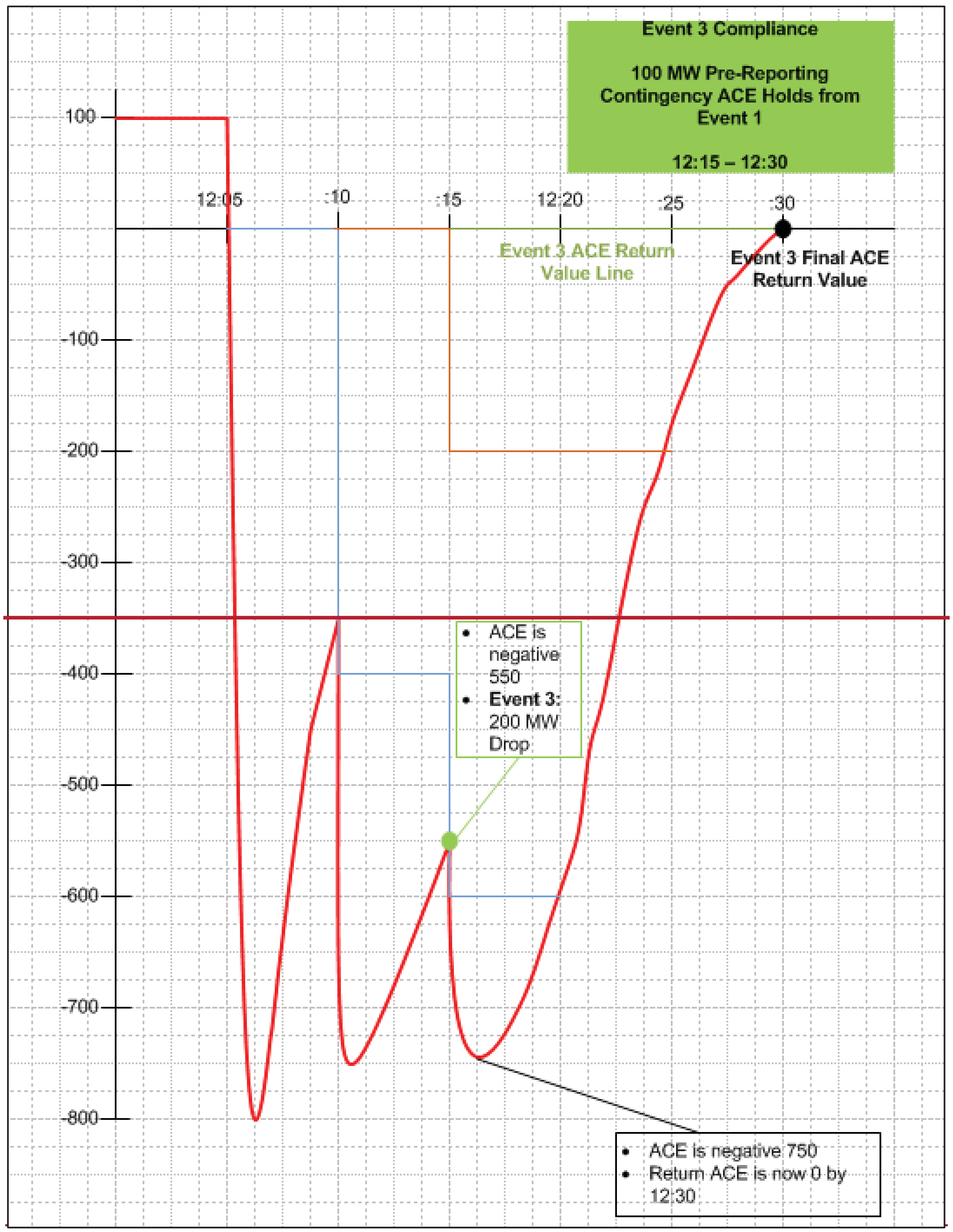
~~However, the Responsible Entity experienced another Contingency Event (Event 3) based upon the following:~~

- ~~ACE had recovered to negative 550 – prior to Event 3~~
- ~~Time of the Contingency Event - 12:15~~
- ~~Size of the Contingency Event - 200 MW~~
- ~~Responsible Entity Reporting ACE post Contingency Event – negative 750~~

~~At the time of Event 3, the Responsible Entity would reduce the value of its required recovery from the Balancing Contingency Event 2 by the size of Contingency Event 3 at 12:15, thus lowering the required ACE recovery from Event 2 to negative 200 MW. The Responsible Entity would demonstrate recovery from both Balancing Contingency Event 1 and Balancing Contingency Event 2, taking in to account Event 3, by returning its Reporting ACE to at least a negative 200 MW by 12:30.~~

~~The following demonstrates the logic used for compliance following Event 3 (from 12:15 – 12:30).~~

~~Event 3 Compliance~~



~~The Responsible Entity's required ACE Value of recovery from final Event 3 is 0 MW (the same as it was from the initial Balancing Contingency Event 1 prior to any subsequent events)~~

- ~~Time of the Balancing Contingency Event - 12: 15~~
- ~~Size of the Balancing Contingency Event - 200 MW~~
- ~~Responsible Entity MSSC - 2,000 MW~~
  ~~Resulting Responsible Entity's ACE Value following the Balancing Contingency Event – negative 750 MW~~

~~With no additional Contingency Events, the Responsible Entity must demonstrate recovery of final Event 3 by returning its Reporting ACE to the 0 MW ACE value of 0 MW of recovery from the initial Event 1 within the Contingency Event Recovery Period, or by 12:30.~~

~~The above examples illustrate the minimum response for compliance. Actual events and recoveries will differ because of matters such as, but not limited to, Contingency Reserve being deployed differently.~~

~~Attachment 3~~

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

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7 "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

8 "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

9 Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

10 Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

11 Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1
  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- Example 2
  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA’s ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- Example 3
  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

Project 2010-14.1 Mapping Document
Transition of BAL-002-0 to BAL-002-2

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R1	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R2	This requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R3	Requirement R1 and R2	This requirement was broken apart. The requirement was defining two separate actions; 1) to require activation of Contingency Reserves, and 2) to require having Contingency Reserves equal to its MSSC.
BAL-002-0 R4	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" definition.	Requirement R1 mandates recovery from a Reportable Balancing Contingency Event. A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R5	This Requirement has been moved into BAL-002-2 Requirement R1 and "Reserve Sharing Group Reporting ACE" definition.	A portion of this requirement was defining how a RSG calculates its ACE. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.
BAL-002-0 R6	This Requirement has been moved into the BAL-002-2 Requirement R3 and "Contingency Event Restoration Period" definition.	Requirement R3 mandates restoration of Contingency Reserve following a Balancing Contingency Event. A portion of this requirement was defining the timing for restoration of Contingency Reserve after an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Project 2010-14.1 Mapping Document
Transition of BAL-002-0 to BAL-002-2

Standard: BAL-002-0 – Disturbance Control Standard		
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BAL-002-0 R3	Requirement R1 and R2	This requirement was broken apart. The requirement was defining two separate actions; 1) to require activation of Contingency Reserves, and 2) to require having Contingency Reserves equal to its MSSC.
BAL-002-0 R4	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" ~~and "Contingency Reserve Restoration Period" definitions.~~definition.	Requirement R1 mandates recovery from a Reportable Balancing Contingency Event. A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standard: BAL-002-0 – Disturbance Control Standard		
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BAL-002-0 R6	This Requirement has been moved into the BAL-002-2 Requirement ~~R1~~R3 and "Contingency Event Restoration Period" definition.	Requirement R3 mandates restoration of Contingency Reserve following a Balancing Contingency Event. A portion of this requirement was defining the timing for ~~recovery from~~restoration of Contingency Reserve after an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Formal Comment Period Open through August 20, 2015
Ballot Pools Forming through August 5, 2015

Now Available

A 45-day formal comment period for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern, Thursday, August 20, 2015.**

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 5, 2015**.

Since the ballot pools for this project are outdated, new ones are being formed in the **Standards Balloting & Commenting System (SBS)**. If you previously joined the ballot pools for BAL-002-2, you **must** join these ballot pools to cast a vote. Previous BAL-002-2 ballot pool members **will not** be carried over. Registered Ballot Body members in the SBS may join the ballot pools here.

Next Steps

An **additional** ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 11-20, 2015.**

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Survey Report

Survey Details

Name 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls | BAL-002-2

Description

Start Date 7/7/2015

End Date 8/20/2015

Associated Ballots

2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 IN 1 ST

Survey Questions

1. Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.

Responses By Question

1. Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Our entity, as a Generation only BA, currently under BAL-002-1 uses “Coordinated adjustments to interchange schedules” as the primary method of meeting the standard. The new standard BAL-002-2 Rev 7 is not clear if “Coordinated adjustments to interchange schedules” will be allowed. We feel the language needs to be clarified as to what is allowed as contingency reserve since “The provision of capacity that may be deployed by Balancing Authority” is vague.

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Our entity, as a Generation only BA, currently under BAL-002-1 uses “Coordinated adjustments to interchange schedules” as the primary method of meeting the standard. The new standard BAL-002-2 Rev 7 is not clear if “Coordinated adjustments to interchange schedules” will be allowed. We feel the language needs to be clarified as to what is allowed as contingency reserve since “The provision of capacity that may be deployed by Balancing Authority” is vague.

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

EEI, as a Generation only BA, currently under BAL-002-1 uses “Coordinated adjustments to interchange schedules” as the primary method of meeting the standard. The new standard BAL-002-2 Rev 7 is not clear if “Coordinated adjustments to interchange schedules” will be allowed. We feel the language needs to be clarified as to what is allowed as contingency reserve since “The provision of capacity that may be deployed by Balancing Authority” is vague.

Document Name: Project_2010-14_1_BAL-002-2_Unofficial_Comment_Form_07072015.docx

Likes: 0

Dislikes: 0

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5 -

Selected Answer:

Answer Comment: No Comment just want to vote Yes

Document Name:

Likes: 0

Dislikes: 0

John Shaver - Southwest Transmission Cooperative, Inc. - 1 -

Selected Answer:

Answer Comment: x

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: none

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment: No issues

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: none

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: none

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:

We appreciate that the drafting team has removed the zero defect component of the standard and that the current draft acknowledges that reserves should be deployed to address multiple reliability issues.

Our primary concerns are the following:

R1.1.2, reporting events should be covered in the compliance section of the standard, not a requirement. Please refer to NERC's paragraph 81 criteria "B4 Reporting", which notes that documentation should not be included in a standard as a requirement.

The standard should retain a simple quarterly report form rather than creating forms for each report. The reasoning the drafting team gave for not adopting this recommendation is not substantiated. It just says that VSLs for small entities will be Severe without providing examples. Performance is performance. Size has no impact in this standard. VSLs are just a starting point in the enforcement process. Regional enforcement staff will determine the seriousness and risk associated with a violation. We can provide a simple example of a form that would work for this standard. It would keep reporting simple and provide NERC the data it needs for its State of Reliability Report.

While not primary concerns, the standard could be clearer if the following changes were made:

Under the term for a Balancing Contingency Event, a change in ACE is only mentioned for the loss of generation, not the other resource losses. It's probably not necessary to mention change in ACE as a resource loss is a resource loss.

The last two and a half lines of the MSSC definition are unnecessary. The definition can be:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority.

For the definition of Contingency Event Recovery Period, since small events can happen in sequence (such as runbacks or individual generator trips on a combined cycle plant), the recovery period should not start with the initial decline as the BA may not know they are in a DCS event until the event has played out. Recommend changing the wording be changed to "begins at the time when ACE reaches the reportable threshold of a Balancing Contingency Event, and extends for fifteen minutes"

We can provide a redline of the standard that has minor housekeeping edits that would simplify wording upon request.

Document Name:

Likes: 0

Dislikes: 0

Russel Mountjoy - Midwest Reliability Organization - 10 -

Selected Answer:

Answer Comment:

MRO supports the intent of BAL-002-2 however, MRO does not support the addition of R1.2. R1.2 is purely adminstrative in nature and reporting should not be part of a reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

As a stakeholder of MISO, we are supporting their comments.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

We have three primary concerns with this standard:

- R2 is ambiguous as to what is meant by “review and maintain annually, and implement”. While it looked like the drafting team moved away from a zero defect standard (where reserves must be > MSSC every hour), the RSAW implies that the ERO interprets this wording differently. The drafting team’s intent should be clear in the measure that operators should not be discouraged to deploy reserves when needed, but they do need an approach to be notified when reserves are low and a means to replenish them.

- The Paragraph 81 criteria note that reporting and filling out paperwork should not be a requirement, yet there is such a requirement to "document all Reportable Balancing Contingency Events using CR Form 1". Rather than a requirement, this should be explained in the compliance section of the standard.
- We do not agree with the move away from simple quarterly reporting. While there is stray wording in Order No. 693 on compliance for single events, this does not preclude submitting a quarterly report. As it is, NERC will likely still request this data for "State of Reliability Reporting" and then auditors will ask to see the reports again as well.

As the current standard is structured, it looks like it will cause BAs to request EEAs whenever reserves are reduced to address day to day balancing issues. Even though there is no change in reliability, the likely step increase in EEAs will likely trigger other concerns, the solution for which would likely be another standard. The standard should be clearer in the measure and supporting information that reserves can be drawn down, but the BA needs an approach to replenish them or call EEAs if unable to do so.

We had additional comments that would make the standard simpler or clearer. These have been previously sent to the drafting team.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Hydro-Quebec TransEnergie supports NPCC comments.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

The IESO thanks the SDT for revising the previous R2 to remove those parts that contain confusing language and are deemed unnecessary.

However, we are still unable to find the need and reliability benefit of R3 which requires a BA to restore its Contingency Reserve to at least its Most Severe Single Contingency (MSSC) before the end of the Contingency Reserve Restoration Period given the need to meet R1 except under the specified conditions which include events occurring during Contingency Reserve Restoration Period. By virtue of meeting R1, a BA must have Contingency Reserve that equals or exceeds MSSC at all time (expect under the conditions in Part 1.3). Replenishing Contingency Reserve is thus an implicit requirement in R1. Having an explicit requirement for replenishing reserve in R3 will expose Responsible Entities to potential double jeopardy, is unnecessary and adds no reliability value.

As an illustration, failing R1 except under certain conditions which include the Contingency Reserve Restoration period implies that a BA didn't have sufficient contingency reserve to meet the ACE recovery requirement stipulated in R1. Failing R3 means a BA did not restore (or have) sufficient contingency reserve except during the Contingency Reserve Restoration period. Note that an event may or may not occur at a time when a BA does not have sufficient CR, so a BA may fail R3 alone but not R1. However, the reverse is not true. A BA that fails R1 will most likely (if not invariably) also fails R3, hence the double jeopardy.

Having only R1 would suffice as this requirement will drive a BA to recover or have sufficient CR except under certain conditions.

We therefore once again propose that R3 be removed.

Document Name:

Likes: 0

Dislikes: 0

Rob Vance - NB Power Corporation - 5 -

Selected Answer:

Answer Comment:

We also submitted our comments through NPCC. We feel the intent of the 3rd bullet of Requirement 1.3.1 is to ensure that all required reserve up to the MSSC required reserve value is used prior to the waiver of Requirement 1.1 becoming available. The current wording suggests that you need only deplete reserves to a value less than the MSSC required reserve amount and the waiver will be enabled. This would wave the normal requirement to restore ACE even while leftover reserve is still available. We feel the wording "the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency" should be changed to read "the Responsible Entity has depleted its Contingency Reserve by at least the amount of reserve required for its Most Severe Single Contingency".

Also, we feel the same R1.1 waiver should apply for multiple contingencies that use all of the required reserve regardless of whether a declared Energy Emergency Alert is in effect. An EEA is used only if there are already insufficient reserves to meet requirements or an expectation of not meeting requirements. In the case of a non-emergency normal restoration that doesn't require a declared emercy but becomes difficult near the end of the Contingency Event Recovery Period, the time it takes to declare an emergency may extend the actual recovery beyond the Contingency Event Recovery Period thereby creating a non-compliance. The exemption in the current BAL-002-1 standard (see section 1.5 of part D of the standard) does not require a previously declared emergency. If necessary, a declaration of an Energy Emergency Alert can be made ASAP ***after*** a restoration has failed to meet the Contingency Event Recovery Period requirement.

Document Name:

Likes: 0

Dislikes: 0

David Kiguel - David Kiguel - 8 -

Selected Answer:

Answer Comment:

The SDT should be commended for its work in putting forward this draft. However, there are a number of areas where the draft can be improved before adoption by NERC.

1. R1.3 is confusing. Instead of detailing what the Responsible Entity must do, it extends to details on what is NOT subject to compliance. Results based standards must focus on what reliability objectives are to be achieved rather than what is not subject to compliance. All after “however, it is not subject to compliance with Requirement 1, part 1.1….” does not belong in the requirement. It could be part of the Compliance Section.

2. Sub-Requirement R1.2 refers to documentation and as such is administrative in nature, i.e. does not contribute to Reliability. Furthermore, it seems to meet Criterion B4 of the Paragraph 81 Criteria.

3. Requirement R3 seems to contain obligations that are related to/repeated from R1. The obligation to restore Contingency Reserve should be merged into R1.

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

R1.2. should not be included in the requirements section. This administrative function would violate FERC P81 as administrative in nature. Also, the process or form could change.

R1.3. AZPS is concerned that the NERC Glossary of Terms only allows a BA or LSE to be in an EEA. And EOP-002-3.1 R7 and R8 have the Balancing Authority requesting to be declared in an EEA. If a Balancing Authority were in an RSG, that would make the RSG the Responsible Entity under BAL-002-2. If the BA was experiencing and requested an EEA, does this transfer exception allowed in R1.3 to the RSG as not being subject to compliance?

R2. If we understand correctly, this requirement is extending the requirement of EOP-011-1 R2 by reference. We do not believe it is advisable to include a requirement that adds to the elements of another requirement in a separate standard. It raises tangential questions such as “does this Operating Process have to be RC-approved as the Operating Plan does?”

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

BPA is in agreement with the proposed standard. However, BPA believes there should be a clarifying comment in requirement R1. In R1, sub-requirement 1.1, following the second bullet, BPA would like the standard to state:

The recovery value for any Balancing Contingency Event(s) that occurs during the Contingency Event Recovery Period shall be the recovery value for the initial event.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

1. The High VSL for R2 in the proposed BAL-002-2, as well as auditor guidance in the proposed BAL-002-2 RSAW, could be interpreted to require Contingency Reserve to be > MSSC at all times other than when deployed in response to a Balancing Contingency Event. However, in the Western Interconnection BAL-002-WECC-2 allows clock-hour averaging to determine if Contingency Reserves were adequately maintained. How will this apparent conflicting methodology be reconciled if BAL-002-2 is passed?
2. The definition of Contingency Reserve in the proposed BAL-002-2 indicates this is capacity that may be deployed to respond to a ***Balancing Contingency Event***. However, R3 states "Each Responsible Entity, following a ***Reportable Balancing Contingency Event***, shall restore Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period...". The proposed standard does not identify how long an entity has to return Contingency Reserve following deployment for a ***Balancing Contingency Event (i.e. -*** not "Reportable").

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

I am recommending a NO vote for the following reasons:

1. A specific percent change in ACE (Area Control Error) needs to be specified in the definition of ***Reportable Balancing Contingency Event***, where it states ***"…sudden decline in ACE based on EMS scan rate…"*** (on page 3).

2. Using arbitrary MW definitions for each major Interconnection (on page 4) under the same section on the definition of a ***Reportable Balancing Contingency Event***, may lead to inconsistent results, as the MW values actually needed are dynamic and based on the amount of load and on-line generation at the time of the disturbance or contingency event.

3. Under the ***Contingency Reserve Restoration Period*** definition on page 4, the ***period*** should be ***30 minutes*** instead of ***90 minutes*** in order to be consistent with the NERC TOP-004 (Transmission Operations) Standard.

4. Under ***the Rationale for Requirement R1*** on page 7, the phrase ***"..returns its Area Control Error (ACE) to defined values…"*** should include a

locational reference to the actual ***defined values*** (i.e., what are they and where can they be found ?).

Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

209-526-7414

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

ReliabilityFirst votes in the Affirmative because the standard helps to better ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. ReliabilityFirst offers the following comments for consideration:

1. Requirement R1, Part 1.3.1

i. There is a disconnect between the lead in Part 1.3.1 and the third bullet. The lead in states “the Responsible Entity is:” and the third bullet states “the Responsible Entity has depleted…”. As one can see, there is a double use of the term “the Responsible Entity”. RF recommends the following language for consideration:

1.3.1 the Responsible Entity:

• [is] experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and

• [is] utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

• has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

Document Name:

Likes: 0

Dislikes: 0

Edward Magic - SCANA - South Carolina Electric and Gas Co. - 5 -

Selected Answer:

Answer Comment:

R 1.1.2 Reporting should not be a requirement.

R2 M2 Contingency Reserves can and should be deployed for reasons to include loss of resources temporarily till mitigation measures are implemented less than MSSC. M2 does not make it clear that reserves can be used for any other resource loss less than MSSC. It appears you have to provide data that you had reserves >= MSSC each hour.

The BAL-002-2 RSAW posted further supports our primary concern “Review the evidence and verify that the entity had available Contingency reserves equal to, or greater than its Most Severe Single Contingency” Suggest the wording be revised “Confirm the applicable Entity met the Contingency Requirement for Reportable Balancing Contingency Event(s)”

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - LG&E and KU Energy LLC - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6

Voter Information

Voter	Segment
Joseph Bencomo	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy LLC	SERC,RFC

Selected Answer:

Answer Comment:

These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): LG&E and KU Energy, LLC and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RFC and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

Comments

Clarity is needed as to whether or if a BA that is a member of an RSG but does not request RSG assistance for a specific BCE is considered the Responsible Entity. The “active status” language used in 4.1.1.1 is unclear.

Suggested solution – Modify language in 4.1.1.1 to:

4.1.1.1. A Balancing Authority that is not a member of a NERC registered Reserve Sharing Group is the Responsible Entity.

The proposed draft 7 requires reporting and compliance evaluation of each individual Reportable BCE. Quarterly reporting and evaluation of Reportable Events on a quarterly basis has worked well and should be continued.

BAL-001-2 becomes enforceable 7/1/2016, R2 (BAAL performance) will incent the appropriate BA/RSG action to a Reportable BCE without forcing action that could be contrary to interconnect frequency stability. BAL-001-2 has negated the need for BAL-002-2.

The language in R1.3 related to an exemption from R1.1 needs to be applicable to R1 and R3.

An entity experiencing an EEA (or any of the other exemption scenarios in R1.3) should not be required to restore ACE as stated in R1.1, document the Reportable BCE as per 1.2 or restore Contingency Reserves to MSSC within the Contingency Restoration Period as stated in R3.

For a Responsible Entity experiencing an EEA, compliance with BAL-002-2 R3 is not consistent with actions required under the EEA.

Suggested solution – Modify language in 1.3 to:

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 parts 1.1 and 1.2 and R3 if:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

With the requirements as written, the Responsible Entity should include the Reliability Coordinator. As defined in the NERC Reliability Functional Model Version 5 for the Reliability Coordinator, **Balancing operations**:

"**Balancing operations.** The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability."

Consider incorporating Requirement R3 into Requirement R1 by adding the following Part 1.4:

1.4 Restore its Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period.

Regarding the wording used to define the **Most Severe Single Contingency (MSSC),** as it reads now the MSSC is defined as "The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss ...".

The process used to find the MSSC uses system models and does allow the modelling of contingencies.
For clarity, suggest revising the wording in the definition. The models themselves neither identify contingencies nor are contingencies "maintained in" them. Suggest eliminating the words "…as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group…"or replacing the words "identified and maintained in the system models within" with the following: "identified using system models maintained within…".

We feel the time requirement to declare an EEA of any level prior to 1.1 being waived is an unnecessary operations burden during the Contingency Event Recovery Period. It could result in an entity being non-compliant because complete recovery is delayed by the time it takes to go through the "declaration" process. We feel the new standard is adding an exposure to non-compliance because of the need for the RC to declare an emergency prior to the waiver of the ACE correction requirement in Part 1.1. Within NPCC there are entities that fill both the RC role that declares the EOP-002-3 Energy Emergency Alert level, and the BA role that BAL-002-2 will apply to.

In addition, the wording in the third bullet of Part 1.3.1 (Part 1.3.1 needs identification in the draft) needs clarification. For example, if your MSSC is a resource loss of 400 MW, this Part's wording would suggest that the depletion of "Contingency Reserve to a level below its Most Severe Single Contingency" would refer to a value of less than 400 MW. You might deplete your reserves by

250 MW and still have 150 MW remaining to meet another contingency after the initial event which may be sufficient and not require a waiver. We suspect that the intention is that all of the MSSC determined value of required reserve is depleted before the waiver is allowed.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jes Gray	Omaha Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We would suggest to the drafting teams developing coordinated efforts with the Alignment of Terms Standards Draft Team (Project 2015-04). The collaborative efforts would pertain to the revised and newly proposed terms in BAL-002-2 which would help ensure that these terms are included in both the NERC Glossary of Terms as well as the Rules of Procedure for proper alignment (which can be addressed in Phase II of their project). Of course, this collaborative effort would take place once NERC's BoT and FERC approves the proposed terms and standard pertaining to this current project.

Our review group also noticed that the drafting team uses the acronym 'RE' several times (second paragraph on page 4) in the Rationale for Contingency Reserve Definition section of the standard. We will make the assumption that you are referring to the term 'Responsible Entity'. However, we would suggest either using it as an appositive with the term or removing it from the document completely. We feel that some confusion will arise amongst the industry on what 'RE' is being referred to. For example, 'RE' could refer to 'Regional Entity' or 'Registered Entity'.

In the Rationale section for Requirement R1, the drafting team mentions “The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language”. We would ask the drafting team to provide more clarity on what direction BAL-002-2 is going in reference to the EEA. The rationale states that the drafting team has developed proposed language. Can we assume this proposed language is currently in the standard and if so, will this language match up with the NERC’s process changes to the EEA levels (which hasn’t been developed yet)? The next question would be….will these process changes be vetted through the voting process or will it be the law of the land?

Our group understands that the conversation pertaining to the retirement of BAL-002-2 is in the distant future. However, we have the concern that there are current documentation in place that helps serve the industries needs in reference to the MSSC. With that being said, we feel that BAL-002-2 brings confusion and redundancy to the industry and we would suggest that the drafting team take into consideration the retirement of this standard.

Finally, we would like to suggest to the drafting team once the terms and standards have been approved by the NERC BoT and FERC to follow up on this project and ensure that the RSAW be properly aligned with this standard.

Document Name:

Likes: 0

Dislikes: 0

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Information

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Christina V. Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer:

Answer Comment:

The SRC agrees with the intention of the SDT draft 7 posting to:

· Provide the risk based parameters (ACE range, Recovery period, Restoration period) for responding to a Balancing Contingency Event (BCE);

· Ensure that the definition of Most Severe Single Contingency (MSSC) does not include more than one resource;

· Ensure that the definition of BCE does recognize the possibility of the loss of more than one resource;

· Eliminate draft 6's hourly obligations; and

· Clarify that shedding load is not an expected action in order to maintain reserves.

The SRC does not agree with proposed standard wording that:

- Links MSSC to BCE; and
- Links Contingency Reserves (CR) to Disturbance Control Standard (DCS) compliance.

The SRC proposes clarifying modifications to definitions for:

- Balancing Contingency Events;
- MSSC;
- Contingency Event Recovery Period; and
- The EEA level referenced in R1.3.1

The SRC again asks the SDT to remove the language within draft 7's proposed CR requirement that ties DCS compliance to the use of CR.

The SRC has characterized its comments in three classifications: those proposed to facilitate clarity; those proposed to ensure that the focus of requirements remains on reliability; and those proposed to address other concerns.

Revisions Proposed To Facilitate Clarity

The SRC would ask that the SDT to redraft the requirements in more direct terms. Phrases like "demonstrate recovery" in the requirement section of the standard can be construed ambiguously and a clear reliability requirement omits unnecessary words and directly defines the obligation.

In particular, the SRC suggests that the linkage between R 1.1 and R1.31 is a source of ambiguity within the standard because:

· Requirement R1.1 defines the target ACE correction (range of recovery);

· Requirement R1.3 defines Contingency Reserve deployment;

· Sub-Requirements of R 1.3 then introduce exceptions for **R1.1** (*i.e.*, R 1.3.1 and R 1.3.2).

This organization does not allow readers and entities responsible for compliance and direct correlation between specific defined obligations and the proposed exemptions. To facilitate clarity, the SRC offers two recommendations. The first recommendation preserves much of the current, draft language while the second recommendation provides more streamlined language:

1. Retaining current draft language:

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

• zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

• its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if: **1.3.1** the Responsible Entity is:

Unless:

· the responsible entity:

• is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher; is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan; or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency .

or,

· the following subsequent event(s) occur:

1.3.2 the Responsible Entity experiences:

• multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Even;, or

• multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

1. *More direct version*:

R1. Unless the Responsible Entity is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher, is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, , the Responsible Entity experiencing a *Reportable Balancing Contingency Event* (RBCE) shall return its ACE to:

- Zero within the *Contingency Event Recovery Period* if the Responsible Entity's Pre-RBCE ACE Value were positive or equal to zero; or

- Its Pre-RBCE ACE Value if the Responsible Entity's Pre-RBCE ACE Value were negative

Where a Balancing Contingency Event exceeds the responsible entity's MSSC or multiple Balancing Contingency Events occur within the Contingency Event *Restoration period* of the 1st RBCE, the responsible entity shall deploy contingency reserves, but such response shall not be subject to Requirement R1:

Revisions proposed to ensure that the focus of requirements remains on reliability

The SRC asserts that the primary focus of BAL-002 should be reliability (ACE recovery) with less focus be given to the specific process regarding how to meet the reliability requirement. The current draft appears to link economic sharing arrangements (Contingency Reserves) to a reliability requirement and, therefore, precludes the use of more effective processes to meet the reliability requirement. The SRC cautions the SDT against mandating the use of a process where such usage would be inappropriate from both a reliability and cost efficiency perspective when other processes are available For example, as written, draft 7 could preclude the use of Demand Side Management (DSM) as Contingency Reserves (in contradiction of Order 1000), and restricting DSM to Emergencies only. For these reasons, the requirements should be re-focused on what needs to occur for reliability – not how such activities are performed.

The SRC does recognize the SDT's attempt to address the issue of maintaining reserves designed to preserve serving load verses the issue of shedding load to preserve reserves and that it makes no sense to shed load to maintain reserves that are designed to protect load from being shed.   Additionally, the SRC questions the need for the proposed Requirement R2 (*i.e.*, the requirement to have a method to compute MSSC). Such requirement is administrative in nature as it mandates a creation of a procedure, an implementation process for that procedure, as well as a mandate to "have" a market service to calculate MSSC. The sentence in draft 7 can be read as ether:

- an annual obligation to compute MSSC and to use that annually-computed MSSC in system operations, and
- carry an equivalent amount of reserves for that year

or

- develop a plan to explain how to compute MSSC and review that plan every year
- implement the computation (the implication is that the plan will introduce the time frame for updating MSSC)
- carry an equivalent amount of RC (for as long as the plan states)

The definition of MSSC is axiomatic and does not require a formal procedure. The only plausible justification for having such a plan is mandate self-imposed rules regarding when to compute MSSC; how to apply that calculation; and for how long. Given the ambiguity in draft 7's R2, either approach can be justified. Such ambiguity would not serve reliability. As an example, if draft 7 really did intend linking MSSC to an annual value, and in doing so lock-in a minimum reporting value (80% of MSSC), then what could occur is that small BAs can have a minimum reportable value that is larger than any unit that is operating on a given day – in effect - exempting them from ever reporting. On the other hand, if draft 7 really did intend to provide flexibility to the BAs, a number of questions arise: Is this a daily scheduling function, or a continuous operating function? Is the objective fixed or does it depend on what is operating at the given time? Accordingly, the current approach could be interpreted broadly and variably and should be revised as it does not appear to be directly focused on or facilitating reliability.

Revisions Proposed to Address Other Concerns

The SRC suggests the following comments and/or revisions for the SDT's consideration:

1. Delete the phrase “within system constraints” in Requirement R1. Because BAs are not responsible for system constraints (that’s the role of TOP), the inclusion of this phrase connotes that a BA can be held responsible for exacerbating a SOL problem, even if the BA had no knowledge of the limit and was taking actions to comply with its obligations. The requirements should respect current roles and responsibilities of the various functions and, currently, the TOP is responsible for directing the BA in this regard.

2. The standard has a reporting requirement, but does not include a reporting timeframe. Therefore, the most conservative assumption would be that reporting is on and “individual event” basis. For draft 7, the SDT rejected quarterly reporting based on a non-relevant paragraph in Order 693.

354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC’s position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.

The SRC requests that the SDT explain its correlation between the reporting requirement and P 354 and requests that the SDT clarify the timing of any required reporting. Additionally, the SRC is unclear as to how “the VSL levels developed were likely to place smaller BA’s and RSGs in a severe violation regardless of the size of the failure.” Upon review, it appears that values for entities are calculated on a % of recovery whether applied to an individual event or quarterly performance – accordingly the severity of a violation would still be correlated to overall performance for some time period. The SRC requests that the SDT re-evaluate its explanation and provide additional clarification.

1. The Draft 7 definitions of MSSC and BCE do not resolve the issue of BCE being greater than the MSSC because Draft 7 continues to link the definitions of MSSC and BCE. The SRC believes MSSC is an a priori / actual state value while BCE is an a posteriori event/experience. The SRC agrees with the SDT that MSSC can never be more than one resource otherwise it would not be a “single contingency.” BCE on the other hand can (as the current definition indicates)

include the impacts of the loss of more than one resource. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of MSSC:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Draft 7 definition of Event:

Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or

iii. sudden unplanned outage of transmission Facility;

b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Given the above definitions, the SRC concludes that the SDT correctly wants to ensure that MSSC include large interchange schedule imports as well as large generators. The definition of BCE does that (see sub item B). The draft 7 definition of MSSC relies on the definition of BCE to ensure that such interchange gets considered. The problem is that the foreword of the BCE definition includes the phrase "or any series of such otherwise single events." That addition makes it virtually impossible to quantify / limit one single resource amount for an MSSC.

The SRC would suggest that Draft 7 definition of Event be retained, but that the definition of MSSC be redrafted. The SRC suggests:

MSSC is the MW capacity of the single largest resource scheduled to operate for a given day's peak load. The resource may be a generator (Maximum Continuous Operating Capacity) or a Firm Interchange scheduled import.

This revision:

- Changes the MSSC definition from being linked to a Balancing Contingency Event of undefined size, to linking MSSC to an easily identified single resource capacity/expectation.

- Can be used to provide clarity concerning why and how the amount of CR can be set to a daily MSSC; and how and why every CBE can be "reported" upon without being subject to the DCS objectives for an MSSC.

The Draft 7 definition CR does not define what CR is, but rather defines what CR may be used for. Moreover, the definition's use of the phrase "provision of capacity" requires further explanation to clearly delineate between the concept of "provision of capacity" in the Operating Planning environment (meaning to request that resource be made available to serve load) versus the "provision of capacity" in the compliance/operating environment (meaning the amount of energy that was produced at the request of the BA). An additional issue with the first sentence is that, as written, it specifically excludes the use of those reserves to serve firm customer load. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of Contingency Reserves

Draft 7 definition of Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The SRC suggests that the issue of CR and reserves in general requires an Industry-wide review; and the SDT in its introduction to its Response to Comments propose the ERO conduct such a review prior to making a decision on a final ballot. The review would be used to decide if:

· Reserves were linked to day ahead scheduling in the sense that “reserve” capacity over and above the capacity scheduled to meet a peak load. This concept was referenced in the original Policy 1 – Generation Control and Performance, (dated Feb 1, 1997) at romanette ([i]) If CR were viewed as scheduled available system capacity there would be no issue, because then the measurement of reserves would be focused on the planned capacity for the day. Once that capacity is synchronized it can be used for any and all purposes.

Document Name:	SRC - 2010-14-1 (BAL-002-2) .docx
Likes:	0
Dislikes:	0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

We would like to thank the SDT for their work on this proposed revision to BAL-002-1 and the opportunity to provide comments.

Definitions

MSSC: As written the MSSC definition is linked to and dependent on the definition of a Balancing Contingency Event. In doing so an RE must determine its MSSC based on a Balancing Contingency Event, or series of events including imports, separated by one minute, that have not occurred. As long as the definition of MSSC is dependent on the definition of a BCE, we suggest that MSSC is incalculable and propose the change below.

Most Severe Single Contingency (MSSC): The loss of a single Element as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, or the sudden loss of an import, or the sudden restoration of a Demand that was used as a resource, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Contingency Reserve: As written, the criteria for allowing readiness to reduce Firm Demand in Contingency Reserve is ambiguous. We suggest adding clarifying language to clearly state when the readiness to reduce Firm Demand will be accepted as Contingency Reserve.

We propose the following changes for clarity.

Contingency Reserve: The resource capacity, measured in MW, above that serving Firm Demand, that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

Requirement 1:

We understand the intent of the SDT, however, R1.3 states that an RE must deploy Contingency Reserve for all Report Balancing Contingency Events regardless of whether there is a need to deploy Contingency Reserve to comply with R1.1. Recovery is often accomplished through frequency responsive and regulation resources. Additionally, R1.3 as written could be interpreted to mean that an RE shall deploy ALL available Contingency Reserve, which could be well above MSSC, for ALL Reportable Balancing Contingency Events which could have an adverse impact on Interconnection frequency and BES reliability.

For example, using the PJM minimum synchronized reserve requirements (100% of MSSC, or approximately 1400MW deployed via All-Call) and regulating reserves (+/- 700MW during peak hours); language that suggests a mandatory deployment of Contingency Reserve could result in well over 2100MW, responding to a 900MW reportable event. This response could be much higher since synchronized reserves are typically much greater than the 1400MW requirement and regulation alone could result in 1400MW of response.

We also recognize that the BAAL limits defined in the recently approved BAL-001-2 ensure that an RE will take all available actions to respond to a Reportable Balancing Contingency Event and support Interconnection frequency.

Additionally, we suggest that the phrase “within system constraints” should be removed because BA’s are not responsible for system constraints; that being the role of the TOP. The TOP standards address system constraints and the TOP is responsible for directing the BA in this regard.

Accordingly, we propose the changes below.

1.3. respond to all Reportable Balancing Contingency Events, which may include the deployment of Contingency Reserve, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity is:

• experiencing a Reliability Coordinator declared Energy Emergency Alert Level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

	• the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency **Requirement 2:** We propose the following changes to Requirement 2 to add clarity. **R2.** Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have available Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* **Requirement 3:** With the addition of Requirement 3, either R1.2 should be removed from the standard or the CR Form 1 should be modified to demonstrate Contingency Reserve restoration including subsequent Balancing Contingency Events that may occur within the Contingency Event Restoration Period so that compliance to a Reportable Balancing Contingency Event can be demonstrated with a single document.
Document Name:	
Likes:	0
Dislikes:	0

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2

Selected Answer:	
Answer Comment:	ISO New England does not agree with the SDT's position that an EEA Level 3 is necessary in order to support an exemption from R1. If this were elevated to Level 3 that would imply shedding load in order to maintain reserves and ISO New England understands that this was not the intent. EOP-011 states that a Level 2 EEA is "The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority." meaning all available resources are in use serving load; and " An

energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements." which given the first instance can only be accomplished through arming for load shed to cover the reserves if a contingency were to occur. In the alternative, this would mean shedding actual customer load to maintain reserves before the contingency actually occurs, which is not in the best interest of Reliability.

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. ERCOT supports and incorporates into its comments by reference the comments submitted by the ISO/RTO Council Standards Review Committee. Additional concerns and recommendations are described below by Requirement. Proposed revisions are *italicized*.

1. Definitions – ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability.

2. ERCOT reiterates the need to revise Requirement 1 to provide obligations in more direct terms and with additional clarity and reiterates its comments regarding burdensome and administrative nature of the individual reporting requirement contained within Requirement R1.2 for individual Reportable Balancing Contingency Events. Such reporting does not benefit reliability and could obscure trends or other characteristics that would be obviated by reporting over a longer time period. Perhaps the SDT could consider a time period that is

shorter than quarterly, but clarify that reporting is not on an individual basis triggered by individual events.

3. Requirement R2 –ERCOT respectfully submits that, as proposed, Requirement R2 adds potentially onerous and unnecessary administrative processes and documentation to what has, historically, been a simple, well-established process regarding identification of the MSSC and the procurement of appropriate contingency reserves. To simplify this requirement while retaining the reliability-related aspects of its objective, ERCOT offers the following revisions for the SDT's consideration:

Each Responsible Entity shall document and implement its criteria for identification of MSSC and its processes for review of MSSC and for procurement of contingency reserves greater than or equal to the identified MSSC, which shall be reviewed no less than annually.

Measure 2 could then be modified as follows:

Compliance may be achieved by demonstrating that:

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

• *Criteria for determination of the MSSC;*

• Documentation of its processes for identification of the MSSC and procurement of contingency reserves equal to or greater than its Most Severe Single Contingency; and

· Evidence to indicate that the processes have been reviewed and maintained annually.

ERCOT suggests this alternative because the identification of MSSC is subject to criteria and are part of an overall process to be performed. Further, the proposed requirement presumes a particular structure for responsible entity's compliance processes and procedures that designates the "how" of meeting the requirement instead of the "what." The proposed revision preserves the objective of the proposed Requirement 2 while ensuring that the requirement is results-based and respectful of the various administrative structures established within various entities to administer compliance-related documentation and processes.

ERCOT thanks you for the opportunity to comment upon the proposed Revisions to BAL-002-2. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - BARC Project

Group Member Name	Entity	Region	Segments
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

(1) We applaud the SDT on its efforts to clarify the language of the standard and respond to our previous comments. We continue to believe the SDT is heading in the correct direction during the development of this standard. However, we still have concerns regarding the language, scope, and implementation plan.

(2) We are disappointed that the SDT has not responded or addressed our previous concerns regarding the “Most Severe Single Contingency” definition. From the definition, we believe the applicability reference should be removed entirely. We recommend the definition should read “A Balancing Contingency Event, as identified by the Responsibility Entity and maintained in its system models, that would result in the greatest loss of resource output at the time to meet Firm Demand and export obligations, excluding those export obligations for which Contingency Reserve obligations are being met by a Sink Balancing Authority.” We also recommend the removal of the MW measurement, a unit of power, as a Balancing Contingency Event is a moment in time.

(3) Likewise, we wish the SDT would further clarify this standard's applicability. We understand the need to address the instance when a BA fails to meet the membership requirements of a Reserve Sharing Group (RSG). We recommend that Section 4.1.1.1 should be split as follows, "4.1.1.1 A Balancing Authority is the Responsible Entity that is not a member of a Reserve Sharing Group" and "4.1.1.2 A Balancing Authority that is a member of a Reserve Sharing Group and 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 Reserve Sharing Group."

(4) The SDT needs to address our previous comments regarding the "Reportable Balancing Contingency Event" definition. We recommend the removal of "Prior to any given calendar quarter..." from the definition, as it implies the need for an additional requirement for Responsible Entities to coordinate an exception from the rest of the definition which is based on a percentage of the MSSC or an Interconnection-based amount. Furthermore, we continue to believe that the thresholds in the definition are arbitrary, and ask that the drafting team provide a technical basis for these values. In many cases, the values selected are below the median values identified in Attachment 1 of the background document. By not documenting the more frequently occurring values annually, we fear this could cause issue later on in the standard development process. We recommend moving the identification of these values, and supporting background for their selection, to an attachment within the standard, similar to the approach taken in NERC Standard BAL-001-2.

(5) Under certain situations, a Responsible Entity may not be aware of the significance of a Balancing Contingency Event. For the definition of Contingency Event Recovery Period, the SDT should clarify that the recovery period should not start with the initial decline of resource output, but the instance when ACE reaches the reportable threshold of a Reportable Balancing Contingency Event and fifteen minutes thereafter.

(6) The SDT should consider moving all standard-specific definitions to the NERC Glossary of Terms.

(7) We feel the SDT is overcomplicating the language of Requirement R1. We concur that clarification is needed in the instance when a Balancing Contingency Event follows a single Reportable Balancing Contingency Event. However, embedding a reference to identify what is and isn't required within the same requirement is cumbersome. We recommend moving the embedded reference to another requirement and identify the Contingency Event Recovery Period only applies to a single event.

(8) We have concerns with the VSLs identified for Requirement R1. We agree with the SDT's conclusions that the measured contingency reserve response and required recovery value of Reporting ACE, when is adjusted for other Balancing Contingency Events that occur during the Contingency Event

Recovery Period, are mathematically equivalent. However, the VSLs are based on one approach while the spreadsheet is based on the other. We recommend the SDT select one approach and use it consistently throughout the standard.

(9) We acknowledge the SDT for its response to our previous comments regarding Requirement R1.2. However, we still feel that a requirement for documenting events in a spreadsheet is administrative in nature, and could even be classified as a P81 requirement, as its violation would never result in a harm to BES reliability, especially at a Medium level risk to operations. If an entity only identifies the MW loss and date and time of the event, yet leaves the rest of the form blank, would this result in a violation? As written, the answer would be no, although an incomplete form would not meet the intention of the SDT to provide consistent reporting. We recommend the SDT identify the criteria needed for uniform reporting in a separate attachment to the standard and remove administrative tasks that meet Paragraph 81 criteria.

(10) We recommend the removal of "all Reportable Balancing Contingency Events" as a condition listed in Requirement R1.3. This condition is already referenced in R1. We believe rewording Requirement R1.3 to read "…deploy Contingency Reserve, within system constraints, except when not subject to compliance with Requirement R1 part 1.1 if…" would still satisfy the requirement.

(11) In reference to Requirement R2, we question the need to review an Operating Plan, as such action is already implied with an Entity is "maintaining" their plan. We believe the language identified should be aligned with the language listed within NERC Standard EOP-010-1.

(12) If the intent of the SDT to have Responsible Entities use CR Form 1, then we recommend adding its use in Measure M3 and in the RSAW for R3. A Responsible Entity is already able to use the form to demonstrate its deployment of Contingency Reserve, within system constraints, then it should be able to reuse the form to demonstrate the restoration of Contingency Reserve within the Contingency Reserve Restoration Period.

(13) We disagree with the VSLs identified for Requirement R3 that measure the percentage of Contingency Reserve restoration. The requirement identifies the required time that such restoration must be completed. We recommend replacing with the form "The Responsible Entity restored less than x% but at least y% of required Contingency Reserve following the conclusion of the Contingency Event Restoration Period."

(14) We feel that the bullets of Requirement R1.1 and Requirement R3 are redundant in reference to "any Balancing Contingency Event that occurs during the Contingency Event Recovery Period." We suggest removing the redundant bullets in Requirement R1.1 for clarity, and instead expand Requirement R3 to include a reference to magnitude.

(15) We caution the SDT that references to the term “Reporting Area Control Error” in the rationale for Requirement R1 goes into effect July 1, 2016. The Implementation Plan references that the standard would go into effect six months after FERC approval. Since this term is critical to the definition of “Pre-Reporting Contingency Event ACE Value”, we recommend an update to the Implementation Plan to July 1, 2016 or later as the effective date.

(16) We observe a typographical error within the Implementation Plan regarding the definition of Most Severe Single Contingency. We recommend the removal of the “that is not part of a Res area” reference. The definition should then read “…within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that not part of a Reserve Sharing Group…”

(17) We recommend the SDT fix the title page of the background document to include the document’s title, “Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document.”

(18) We thank the SDT for this opportunity to comment on this standard.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE noticed the VSL for R1 does not address R1.3. The language for R1.3 should be included.

Texas RE noticed the VSL for R2 does not address the review annually portion of the Requirement. VSL should be changed to include “maintain annually”.

Texas RE recommends the VSL for R3 should include Requirement language “at least its Most Severe Single Contingency”.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a BA to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency.

Example of loss of generation in the middle of the night:

If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a Balancing Authority to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. One example would be if there is a loss of generation in the middle of the night. If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Document Name:

Likes: 0

Dislikes: 0

Jamie Lynn Bussin - NaturEner USA, LLC - 5 -

Selected Answer:

Answer Comment:

I. Introduction

NaturEner USA, LLC and its subsidiaries (“NaturEner”) largely support the proposed changes to BAL-002-2, which move the standard towards a performance-based measure of disturbance control response.

While NaturEner largely supports the proposed changes to BAL-002-2, NaturEner believes the standard can be, and should be, even further improved. Specifically, NaturEner recommends that the definition of “Balancing Contingency Event” should be further modified to explicitly include as a qualifying event an unpredicted loss of generation capability. While generator-neutral, the explicit inclusion of this type of event has particular and extreme importance to variable (i.e., renewable) generation, which due to the current inherently imprecise nature of forecasting, unavoidably experience such events at times. The sole reason that NaturEner has abstained in this balloting process, rather than voting affirmative, is because NERC’s proposed definition does not explicitly include as a qualifying event an unpredicted loss of generation capability.

NERC's suggested changes to BAL-002-2 propose the following definition of Balancing Contingency Event:

Balancing Contingency Event: *Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.*

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or

iii. sudden unplanned outage of transmission Facility

b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

NaturEner recommends that the definition should be revised to add a fourth clause to subsection A.a.:

iv. *unpredicted loss of generation capability.*

Revising that definition as suggested is consistent with the underlying reasons for specifying certain events as Balancing Contingency Events, as NaturEner's suggested revision reflects sudden and unavoidable events affecting the grid, and also supports the efficient and effective deployment of resources and the integration of renewable resources. Moreover on a broader basis, though such a revision to the definition is not required for reserve sharing groups to include unpredicted loss of generation capability as a qualifying contingency event under which reserve contingencies can be called upon, such a revision to the definition can only help ongoing efforts to encourage reserve sharing groups who have not yet approved such occurrences as qualifying events to do so now.

II. Reasoning

NaturEner collectively is the owner of three wind farms, the Glacier Wind 1 wind farm, the Glacier Wind 2 wind farm, and the Rim Rock wind farm, as well as two wind-based balancing authorities, NaturEner Power Watch, LLC and NaturEner Wind Watch, LLC.

NaturEner takes wind power forecasting extremely seriously, and has invested significant resources to improve our ability to accurately schedule our generation onto the grid. However, there are some weather events that are extremely difficult to forecast and can cause wind generation units to lose generating capability quickly and unexpectedly. These can result from events such as a sudden change in wind direction due to changing weather regimes or localized effects, or from other complex weather interactions which are not well-captured by state of the art forecasting techniques. Though these events are outside of our control and can result in a sudden and large unpredictable loss of generation, such events are currently not recognized as qualifying events in some regional reserve sharing groups.

For conventional generating units in the west, there are few limitations on the cause or frequency of qualifying contingency events. This is consistent with the underlying purpose and rationale of a reserve sharing group - that there are various extreme events which are unpredictable, unavoidable, and can impact reliability. By pooling the resources of participating Balancing Authorities, reliability can be maintained without requiring individual Balancing Authorities to carry 100% of MSSC in reserves. This is beneficial to the grid, because it avoids costly over-procurement of capacity, while still ensuring the reliability of the system as a whole. The low likelihood that multiple contingencies will occur at the same time means that this shared capacity can be relied upon to be sufficient. Large rapid loss of wind (and solar) events are similarly consistent with the underlying purpose and rationale of a reserve sharing group, in that they there are extreme events which are unpredictable, unavoidable, and can impact reliability. Moreover, if they are appropriately defined and evaluated over a geographically diverse area, they are unlikely to occur at the same time.

The exclusion of extreme loss of wind or solar events from qualifying contingency events leads to at least two negative consequences. First, because the calculation of the resource requirements do not consider regional diversity, the sum of the resource requirements calculated at each individual Balancing Authority-level are much larger than what would be calculated at a system-wide level, leading to systematic over-procurement. Second, due to the increase in capacity resulting from this approach, wind integration tariffs have been implemented in some Balancing Authorities, chilling the ability of new renewable generation to come online in some regions. In contrast, the Midwest ISO has been progressive in implementing market initiatives and programs to enable flexibility in its system and has not needed to increase its reserve capacity as its renewable penetration has increased. The Southwest Power Pool is also a system which has been recognized as a leader in variable integration, and its reserve sharing group makes no limitations on what the cause of a qualifying event is, only that it should be a loss of generation greater than 50 MW. Also with respect to two different weather-related events which result in a loss of generation, members of the Northwest Power Pool (NWPP) are currently allowed to call contingency reserves for high-speed cutouts and for temperature extremes.

With the conversion of BAL-001 to the BAAL standard, the standard approach of using a “CPS2 Analysis” to determine the reserves required to operate reliably will become obsolete. At this point, the timing issue which NaturEner raised in its January 26, 2015 FERC comments to the proposed rulemaking regarding BAL-001 (FERC 20150126-5252, RM14-10) will become more important (in fact, FERC in its Order in that RM14-10 proceeding, suggested that NaturEner raise the subject matter set forth in these comments in this NERC proceeding (151 FERC ¶ 61,048, at page 26, footnote 72)). In a CPS2 analysis, the monthly ACE is evaluated to ensure that reserves are sufficient such that 90% of the 10 minute periods are within L10, regardless of the magnitude. In a BAAL analysis, the ACE will have to be evaluated such that any single 30 minute period should not exceed the BAAL limits. Due to the timing constraints of 15 minute scheduling and the 30 minute BAAL timer, there will be some ACE events which cannot be resolved by modifying interchange schedules. To ensure that a RBC violation will not occur, BA reserves will need to be carried which can resolve the largest such event which could be observed. This will result in an increase in the inefficient deployment of capacity and related transmission reservations in order to maintain compliance for unpredicted loss of generation capability events unless such events qualify as recognized balancing contingency events.

The risk of unnecessary reserve build-outs and holdbacks may be alleviated to some extent if a regional energy imbalance market (“EIM”) is implemented, because the market would settle every 5 minutes, thereby resolving the time constraints outlined in our previous comments. However, RBC will come into effect prior to any operational EIM in the WECC. This may in fact result in a system-wide increase in capacity required to be held in reserve and unnecessary reservation of related transmission, and their associated costs.

Even if and when an EIM is present, however, it still will likely not adequately resolve the problems from unpredicted loss of generation capability unless designed appropriately. It may still cause individual Balancing Authorities to procure more reserve capacity and related transmission than is required to reliably operate the system as a whole. In discussion regarding implementation of an EIM, a resource sufficiency (RS) methodology is being considered by the NWPP to verify that EIM participants enter the scheduling hour with sufficient resources. The work being done in this respect is thoughtful and important. However, the efforts currently being considered also highlight a gap in the existing system in the west. In order to require that participants come to the market “Firm for the hour”, an analysis of the error frequency distribution associated with a Balancing Authority is being done to evaluate error across the next operating hour, using a persistence forecast from 30 minutes prior to the hour. Required reserve capacity will be determined based on a selected probability of events which would exceed that capacity. This work is ongoing, so it is not clear what the final parameters will be, but a probability of 95% has been examined. This analysis will be done on a Balancing Authority level (as opposed to a system-side/reserve sharing group level), and the result of this calculation will be the required reserve capacity needed to allow participation in the EIM.

For smaller Balancing Authorities such as ours, this is a catch-22. To integrate our wind with the system, we want (and should want) to participate in the EIM. However, due to the resource sufficiency requirement, the amount of reserves that a Balancing Authority would need to carry would remain unchanged from the current business as usual because the resource sufficiency requirements still assume the scheduling time frames currently in place, and does not allow the benefits of diversity to be included in the assessment of those requirements. For larger Balancing Authorities, this may not seem to be a problem now, because they may currently have sufficient internal diversity and reserves in their own system to cover the current requirements. However, as load and generation variability continue to increase, thereby requiring capacity reserves to be increased under the considered EIM-related reserve requirements, this inefficiency will also impact those entities, and by extension the cost to the underlying retail consumer.

In order to demonstrate the impact of system-wide aggregation on the reliability of wind generators, the NREL western wind data set [1]from 2006 was used to generate a histogram of the forecast error associated with a regionally diverse subset of the NWPP member states included in that data set. The forecast was assumed to be 30 minute persistence, held constant for the full operating hour. The hysteresis-corrected SCORE value was used to include the impact of both loss of wind and high speed cutouts. A comparison of applying this approach to reserve requirements for both an aggregated 10,000 MW system and an individual 100 MW site are shown in Figure 1 and Figure 2 below. It can be seen that there is much more volatility relative to the installed capacity, which is a result of geographical diversity (i.e., a higher volatility is calculated the smaller the geographic footprint). Further, it can be seen in Figure 2 below that if the proposed resource sufficiency approach was applied at an aggregate system level, and reserve requirements to reach 95% reliability were allocated pro-rata, only 2% of installed capacity would be required. If the individual site level was evaluated to determine the 95% reliability requirements, then the requirements would be 8% or installed capacity, or 4 times what is needed by the system in aggregate. Also note that the NREL data set appears to underestimate the volatility in in the western region, so the actual realized requirements are higher than estimated by that approach.

The impact of calculating a resource sufficiency for an individual site as opposed to an aggregate system is shown in Figure 3 below. On that chart, the x-axis represents the size of the project being evaluated, and the y-axis represents the resource sufficiency requirements calculated using a 95% probability. It can be seen that as the installed capacity reaches about 1,000 MW, the required reserves on a system wide level drop to 2-3% of installed capacity. In the extreme case where the reserves were calculated at the each individual site level, then the result would be 4 times higher.

Figure 3: Comparison of Reserve Requirement Calculated on Aggregate vs individual statistics

III. Recommendations

NaturEner is extremely appreciative of the work that NERC, WECC, PEAK and the NWPP are doing to improve the efficiency and reliability of the grid. Though the issues that we have raised here may have a greater impact in the near term on smaller Balancing Authorities such ours as compared to larger balancing authorities, as shown above the issues represent a detriment to all grid participants and the consumer, an unnecessary and avoidable hurdle (especially to renewable generation), and an inefficient allocation of capacity reserves and related transmission.

A. Revise the Definition of “Balancing Contingency Event” to Include Unpredicted Loss of Generation Capability.

Accordingly, NaturEner requests that NERC revise the definition of “Balancing Contingency Event” to add a clause iv. to subsection A.a. providing for unpredicted loss of generation capability, so that that subsection will then read as follows:

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity’s System,

iii. sudden unplanned outage of transmission Facility, or

iv. unpredicted loss of generation capability

B. Other Suggested Recommendations.

In addition to revising the definition of “Balancing Contingency Event“ as suggested above, NaturEner suggests that NERC’s providing of support and encouragement for the following considerations wherever appropriate would also help both alleviate the problems and advance the benefits discussed above.

1. Efforts should be made to encourage regional reserve sharing groups to allow unpredicted loss of generation capability events as qualifying contingency events, to the extent events are not already allowed by such groups.

a. Qualifying events could be defined using a reasonable persistence probability of exceedance approach.

b. Alternately, the historical contingency events of conventional generators could be evaluated to provide a benchmark for defining the allowable frequency of allowable variable generation contingencies.

2. Requirements for resource sufficiency in energy imbalance markets should be aligned with specified qualifying contingency events in regional reserve sharing groups.

a. Doing so would encourage participation in EIMs, while centralizing the planning for contingency management.

3. Resource sufficiency should be evaluated at a system-wide level, as opposed to at the individual Balancing Authority-level.

a. Failure to do this will result in inefficient and unnecessary acquisition and deployment of capacity and related transmission.

Devon Yates, Manager, Operational Analytics, NaturEner USA, LLC

Document Name:	BAL-002 Supporting Diagrams of Comments 2015-08-20.docx
Likes:	0
Dislikes:	0

Jared Shakespeare - Peak Reliability - 1 -

Selected Answer:

Answer Comment:

While the SDT has responded to comments on the term “sudden” by saying the word does “not need further definition as any definitive definition would be somewhat arbitrary and possibly ill- fitting for one size entity while perfectly reasonable for another,” Peak continues to believe that lack of a clear definition may cause confusion, disagreement and inconsistency. Absent further clarity in the standard, Peak plans to continue to interpret “sudden loss of generation” as instantaneous or when the breaker trips.

The language in R1.1 is confusing with respect to the expectations for multiple Balancing Contingency Events. Please provide an example of the required recovery magnitude and timeline of multiple Balancing Contingency Events.

Please provide a technical justification for the varying thresholds in the different Interconnections. It is unclear why the threshold in the Western Interconnection would be vastly lower than the threshold in ERCOT or even than the Eastern Interconnection. For example, there are 50 units with a PMAX of 500 MW or greater in the Peak RC Area. This is a significant number that will lead to more DCS events that do not significantly impact reliability but will distract from other key monitoring activities.

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

I am voting NO for the following reasons:

1. A specific percent change in ACE (Area Control Error) needs to be specified in the definition of ***Reportable Balancing Contingency Event***, where it states ***"…sudden decline in ACE based on EMS scan rate…"*** (on page 3).

2. Using arbitrary MW definitions for each major Interconnection (on page 4) under the same section on the definition of a ***Reportable Balancing Contingency Event***, may lead to inconsistent results, as the MW values actually needed are dynamic and based on the amount of load and on-line generation at the time of the disturbance or contingency event.

3. Under the ***Contingency Reserve Restoration Period*** definition on page 4, the ***period*** should be ***30 minutes*** instead of ***90 minutes*** in order to be consistent with the NERC TOP-004 (Transmission Operations) Standard.

4. Under ***the Rationale for Requirement R1*** on page 7, the phrase ***"..returns its Area Control Error (ACE) to defined values…"*** should include a locational reference to the actual ***defined values*** (i.e., what are they and where can they be found ?).

Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

209-526-7414

spencert@mid.org

Document Name:

Likes: 0

Dislikes: 0

Additional Comments Received from Steve Johnson – Western Area Power Administration

Thank you for the opportunity to comment on the draft BAL-002-2 standard. Western Area Power Administration would like to provide the following comments:

1. We request clarification on the "system models" information.
2. We would like to request clarification on the clock-hour language that was included in the R2 rationale, but removed. The focus here is that we want to make sure the clock-hour average is still how we will be measured and not individual AGC cycle contingency reserves calculations for carrying sufficient reserves.
3. In 1.3 its stated "deploy Contingency Reserve, within system constraints." We are not sure what is meant by "system constraints" please clarify.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Additional Ballot and Non-binding Poll Open through August 20, 2015

Now Available

An **additional** ballot for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, August 20, 2015.**

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 and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot**.**

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves
BAL-002-2

Formal Comment Period Open through August 20, 2015
Ballot Pools Forming through August 5, 2015

Now Available

A 45-day formal comment period for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern, Thursday, August 20, 2015.**

Commenting
Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools
Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 5, 2015**.

Since the ballot pools for this project are outdated, new ones are being formed in the **Standards Balloting & Commenting System (SBS)**. If you previously joined the ballot pools for BAL-002-2, you **must** join these ballot pools to cast a vote. Previous BAL-002-2 ballot pool members **will not** be carried over. Registered Ballot Body members in the SBS may join the ballot pools here.

Next Steps
An **additional** ballot for the standard and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 11-20, 2015.**

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Additional Ballot and Non-binding Poll Results

Now Available

An additional ballot for **BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event** concluded at **8 p.m. Eastern, Thursday, August 20, 2015**. A non-binding poll of the associated Violation Risk Factors and Violation Severity Levels was extended an additional day to reach quorum and concluded at **8 p.m. Eastern, Friday, August 21, 2015**.

The standard received sufficient affirmative votes for approval and voting statistics are listed below. The Ballot Results page provides a link to the detailed results for the ballots.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
75.92% / 69.26%	79.42% / 69.28%

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 standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

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BALLOT RESULTS

Survey: View Survey Results
Ballot Name: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 IN 1 ST
Voting Start Date: 8/11/2015 12:01:00 AM
Voting End Date: 8/20/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 227
Total Ballot Pool: 299
Quorum: 75.92
Weighted Segment Value: 69.26

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	31	0.646	17	0.354	0	5	21
Segment: 2	9	0.9	4	0.4	5	0.5	0	0	0
Segment: 3	70	1	31	0.738	11	0.262	0	13	15
Segment: 4	25	1	10	0.769	3	0.231	0	9	3
Segment: 5	66	1	25	0.676	12	0.324	0	11	18
Segment: 6	44	1	18	0.75	6	0.25	0	6	14
Segment:	0	0	0	0	0	0	0	0	0

8									
Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals:	299	6.9	127	4.779	56	2.121	0	44	72

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Negative	Comments Submitted
1	Avista - Avista Corporation	Bryan Cox		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican	Terry Harbour		Affirmative	N/A

	Energy Co.				
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A

1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		None	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
1	Lincoln Electric System	Doug Bantam		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Alan MacNaughton		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted

1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Public Utility District	Michiko Sell		None	N/A

	No. 2 of Grant County, Washington				
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		None	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A

2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lisa Martin		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A

3	City of Green Cove Springs	Mark Schultz		Abstain	N/A
3	City of Leesburg	Chris Adkins		Abstain	N/A
3	City of Redding	Elizabeth Hadley		None	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Abstain	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Grand River Dam Authority	Jeff Wells		None	N/A
3	Great Plains Energy - Kansas City Power	Jessica Tucker		None	N/A

	and Light Co.				
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Lakeland Electric	Mace Hunter		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Abstain	N/A

3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A
3	Santee Cooper	James Poston		None	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee,	John Williams		Affirmative	N/A

	FL)				
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		Affirmative	N/A
3	WEC Energy Group, Inc.	James Keller		Negative	Third-Party Comments
3	Westar Energy	Bo Jones		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Abstain	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Abstain	N/A
4	City of Redding	Nick Zettel	Mary Downey	None	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Abstain	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Flathead Electric Cooperative	Russ Schneider		Abstain	N/A

4	Florida Municipal Power Agency	Carol Chinn		Abstain	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Abstain	N/A
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Negative	Comments Submitted

5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Mary Downey	None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Third-Party Comments
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Negative	Comments Submitted

5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		None	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Abstain	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	NaturEner USA, LLC	Jamie Lynn Bussin		Abstain	N/A
5	NB Power Corporation	Rob Vance		Negative	Comments Submitted

5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Omaha Public Power District	Mahmood Safi		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Negative	Third-Party Comments
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A

5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Lewis Pierce		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		None	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Abstain	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Kristie Cocco		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	None	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Third-Party Comments
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Abstain	N/A
6	Florida Municipal Power Pool	Tom Reedy		None	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A

6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel	John Hare	Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A

6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 Non-binding Poll IN 1 NB
Voting Start Date: 8/11/2015 12:01:00 AM
Voting End Date: 8/21/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 220
Total Ballot Pool: 277
Quorum: 79.42
Weighted Segment Value: 69.28

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	69	1	24	0.632	14	0.368	0	11	20
Segment: 2	9	0.6	3	0.3	3	0.3	0	3	0
Segment: 3	66	1	25	0.694	11	0.306	0	21	9
Segment: 4	21	1	10	0.909	1	0.091	0	8	2
Segment: 5	60	1	23	0.676	11	0.324	0	12	14
Segment: 6	41	1	13	0.684	6	0.316	0	11	11
Segment: 7	0	0	0	0	0	0	0	0	0

Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	277	6.5	106	4.695	47	1.805	0	67	57

BALLOT POOL MEMBERS

Show All entries

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Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Negative	Comments Submitted
1	Avista - Avista Corporation	Bryan Cox		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A
1	Beaches Energy Services	Don Cuevas		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee		None	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A

1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
1	Lincoln Electric System	Doug Bantam		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Julaine Dyke		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney		None	N/A

1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	Peak Reliability	Jared Shakespeare		Negative	Comments Submitted
1	Platte River Power Authority	John Collins		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		None	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	Comments Submitted
1	Seattle City Light	Pawel Krupa		Affirmative	N/A

1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
1	Xcel Energy, Inc.	Dean Schiro		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Abstain	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	christina bigelow		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Abstain	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments

					Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lisa Martin		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City of Green Cove Springs	Mark Schultz		Abstain	N/A
3	City of Leesburg	Chris Adkins		Abstain	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Con Ed - Consolidated	Peter Yost		Negative	Comments

	Edison Co. of New York				Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Abstain	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Grand River Dam Authority	Jeff Wells		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker		None	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		Negative	Comments Submitted
3	Lakeland Electric	Mace Hunter		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted

3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Abstain	N/A
3	Platte River Power Authority	Terry Baker		Affirmative	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A

3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Dana Wheelock		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		Affirmative	N/A
3	Westar Energy	Bo Jones		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A

4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Abstain	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Abstain	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		None	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Abstain	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Abstain	N/A
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities	Hien Ho		Affirmative	N/A

	(Tacoma, WA)				
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Negative	Comments Submitted

5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		None	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Abstain	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale	David Gordon		Abstain	N/A

	Electric Company				
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted
5	NaturEner USA, LLC	Jamie Lynn Bussin		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Omaha Public Power District	Mahmood Safi		Abstain	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A

5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Lewis Pierce		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		Negative	Comments Submitted
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Abstain	N/A
5	Xcel Energy, Inc.	David Lemmons		None	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Kristie Cocco		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A

6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Abstain	N/A
6	Florida Municipal Power Pool	Tom Reedy		Abstain	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		None	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern	Joe O'Brien		Negative	Comments

	Indiana Public Service Co.				Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel	John Hare	Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	John J. Ciza		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		None	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A

6	WEC Energy Group, Inc.	David Hathaway		Negative	Comments Submitted
8	David Kiguel	David Kiguel		Negative	Comments Submitted
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 277 of 277 entries

Consideration of Comments

Project Name: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls | BAL-002-2

Comment Period Start Date: 7/7/2015

Comment Period End Date: 8/20/2015

Associated Ballot: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 IN 1 ST

There were 33 sets of responses, including comments from approximately 87 different people from approximately 63 different companies representing 8 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the 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 Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.**

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

1. Please provide any issues you have on this draft of the BAL-002-2 standard and offer a proposed solution for those issues.

Dan Roethemeyer - Dynegy Inc. - 5 -

Answer Comment:

Our entity, as a Generation only BA, currently under BAL-002-1 uses "Coordinated adjustments to interchange schedules" as the primary method of meeting the standard. The new standard BAL-002-2 Rev 7 is not clear if "Coordinated adjustments to interchange schedules" will be allowed. We feel the language needs to be clarified as to what is allowed as contingency reserve since "The provision of capacity that may be deployed by Balancing Authority" is vague.

As drafted, the standard states the requirement, not how to meet the requirement. The proposed language tells how to meet the requirement. As drafted, the standard does not prohibit any adjustments that correct ACE.

Response:

Alex Ybarra - Public Utility District No. 2 of Grant County, Washington - 5 –

Answer Comment:

No Comment just want to vote Yes

Response: **The SDT thanks you for your affirmative response.**

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO

Answer Comment:

No issues

Response: **The SDT thanks you for your affirmative response.**

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment:

none

Response: **The SDT thanks you for your affirmative response.**

Emily Rousseau - MRO - 1,2,3,4,5,6 – MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

We appreciate that the drafting team has removed the zero defect component of the standard and that the current draft acknowledges that reserves should be deployed to address multiple reliability issues.

Our primary concerns are the following:

R1.1.2, reporting events should be covered in the compliance section of the standard, not a requirement. Please refer to NERC's paragraph 81 criteria "B4 Reporting", which notes that documentation should not be included in a standard as a requirement.

The standard should retain a simple quarterly report form rather than creating forms for each report. The reasoning the drafting team gave for not adopting this recommendation is not substantiated. It just says that VSLs for small entities will be Severe without providing examples. Performance is performance. Size has no impact in this standard. VSLs are just a starting point in the enforcement process. Regional enforcement staff will determine the seriousness and risk associated with a violation. We can provide a simple example of a form that would work for this standard. It would keep reporting simple and provide NERC the data it needs for its State of Reliability Report.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT disagrees with the inclusion of a quarterly report in a standard. If NERC or the Regions desire quarterly reporting it should be done under their data collection process.

While not primary concerns, the standard could be clearer if the following changes were made:

Under the term for a Balancing Contingency Event, a change in ACE is only mentioned for the loss of generation, not the other resource losses. It's probably not necessary to mention change in ACE as a resource loss is a resource loss.
The SDT believes that a change in ACE is in the appropriate location in the definition. The SDT agrees with you that a resource loss is a resource loss.

The last two and a half lines of the MSSC definition are unnecessary. The definition can be:

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority.
Some RSGs allow for members to participate in the group on an event-by-event basis. The additional language allows for this flexibility.

For the definition of Contingency Event Recovery Period, since small events can happen in sequence (such as runbacks or individual generator trips on a combined cycle plant), the recovery period should not start with the initial decline as the BA may not know they are in a DCS event until the event has played out. Recommend changing the wording be changed to "begins at the time when ACE reaches the reportable threshold of a Balancing Contingency Event, and extends for fifteen minutes"
There is not an ACE threshold for a reportable event. The reportable event is established by the amount of the resource loss. For the purposes of a runback, if the MW threshold is not reached in a single minute then it would not be considered a reportable event. Therefore, the start of the event

would be the minute in which the threshold is met not the start of the runback.

We can provide a redline of the standard that has minor housekeeping edits that would simplify wording upon request.

Response:

Russel Mountjoy - Midwest Reliability Organization - 10 -

Answer Comment:

MRO supports the intent of BAL-002-2 however, MRO does not support the addition of R1.2. R1.2 is purely adminstrative in nature and reporting should not be part of a reliability Standard.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT agrees that reporting should not be part of a standard.

Response:

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 –

Answer Comment:

As a stakeholder of MISO, we are supporting their comments.

Please refer to the SDT response to the comments submitted by MISO.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 –

Answer Comment:

We have three primary concerns with this standard:

• R2 is ambiguous as to what is meant by "review and maintain annually, and implement". While it looked like the drafting team moved away from a zero defect standard (where reserves must be > MSSC every hour), the RSAW implies that the ERO interprets this wording differently. The drafting team's intent should be clear in the measure that operators should not be discouraged to deploy reserves when needed, but they do need an approach to be notified when reserves are low and a means to replenish them.
The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting.

• The Paragraph 81 criteria note that reporting and filling out paperwork should not be a requirement, yet there is such a requirement to "document all Reportable Balancing Contingency Events using CR Form 1". Rather than a requirement, this should be explained in the compliance section of the standard.
The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

• We do not agree with the move away from simple quarterly reporting. While there is stray wording in Order No. 693 on compliance for single events, this does not preclude submitting a quarterly report. As it is, NERC will likely still request this data for "State of Reliability Reporting" and then auditors will ask to see the reports again as well.

The SDT disagrees with the inclusion of a quarterly report in a standard. Adding a requirement for quarterly reporting would be a Paragraph 81 issue. If NERC or the Regions desire quarterly reporting it should be done under their data collection process.

As the current standard is structured, it looks like it will cause BAs to request EEAs whenever reserves are reduced to address day to day balancing issues. Even though there is no change in reliability, the likely step increase in EEAs will likely trigger other concerns, the solution for which would likely be another standard. The standard should be clearer in the measure and supporting information that reserves can be drawn down, but the BA needs an approach to replenish them or call EEAs if unable to do so.

The SDT is unsure as to what is meant by your comment. There is no requirement in the proposed standard for reserves to be held on a real-time basis, addressing an issue of contention within the current standard. Instead there are requirements addressing correction of ACE, to plan for reserves on a day-ahead basis, and to restore reserve following a Reportable Balancing Contingency Event.

We had additional comments that would make the standard simpler or clearer. These have been previously sent to the drafting team.

Response:

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 – NPCC

Answer Comment:

Hydro-Quebec TransEnergie supports NPCC comments.

Please refer to our response to the comments submitted by NPCC.

Response:

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

The IESO thanks the SDT for revising the previous R2 to remove those parts that contain confusing language and are deemed unnecessary.

However, we are still unable to find the need and reliability benefit of R3 which requires a BA to restore its Contingency Reserve to at least its Most Severe Single Contingency (MSSC) before the end of the Contingency Reserve Restoration Period given the need to meet R1 except under the specified conditions which include events occurring during Contingency Reserve Restoration Period. By virtue of meeting R1, a BA must have Contingency Reserve that equals or exceeds MSSC at all time (expect under the conditions in Part 1.3). Replenishing Contingency Reserve is thus an implicit requirement in R1. Having an explicit requirement for replenishing reserve in R3 will expose Responsible Entities to potential double jeopardy, is unnecessary and adds no reliability value.

As an illustration, failing R1 except under certain conditions which include the Contingency Reserve Restoration period implies that a BA didn't have

sufficient contingency reserve to meet the ACE recovery requirement stipulated in R1. Failing R3 means a BA did not restore (or have) sufficient contingency reserve except during the Contingency Reserve Restoration period. Note that an event may or may not occur at a time when a BA does not have sufficient CR, so a BA may fail R3 alone but not R1. However, the reverse is not true. A BA that fails R1 will most likely (if not invariably) also fails R3, hence the double jeopardy.

Having only R1 would suffice as this requirement will drive a BA to recover or have sufficient CR except under certain conditions.

We therefore once again propose that R3 be removed.

While the SDT appreciates your position, we believe that R3 is significantly different than R1. R1 requires an entity to recover from an event within a 15 minute window. R3 requires an entity to essentially modify their day-ahead plan to address the circumstance in the real-time and to address the next contingency if it were to occur. There is no expectation to carry reserves during the Contingency Reserve Restoration Period. Additionally, Requirement R3 carries forward the intent of the current BAL-002-1 Requirement R6.

Response:

Rob Vance - NB Power Corporation - 5 -

Answer Comment:

We also submitted our comments through NPCC. We feel the intent of the 3rd bullet of Requirement 1.3.1 is to ensure that all required reserve up to the MSSC required reserve value is used prior to the waiver of Requirement

	1.1 becoming available. The current wording suggests that you need only deplete reserves to a value less than the MSSC required reserve amount and the waiver will be enabled. This would wave the normal requirement to restore ACE even while leftover reserve is still available. We feel the wording "the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency" should be changed to read "the Responsible Entity has depleted its Contingency Reserve by at least the amount of reserve required for its Most Severe Single Contingency". The SDT disagrees with your view because all of the three bullets must be met not just the third bullet. In addition, the bullets in R1 part 1.3 are listing the system condition at the time of the Reportable Balancing Contingency Event not following the Reportable Balancing Contingency Event. As an example, if you are not in the EEA prior to the loss, the waiver would not apply. Also, we feel the same R1.1 waiver should apply for multiple contingencies that use all of the required reserve regardless of whether a declared Energy Emergency Alert is in effect. An EEA is used only if there are already insufficient reserves to meet requirements or an expectation of not meeting requirements. In the case of a non-emergency normal restoration that doesn't require a declared emercy but becomes difficult near the end of the Contingency Event Recovery Period, the time it takes to declare an emergency may extend the actual recovery beyond the Contingency Event Recovery Period thereby creating a non-compliance. The exemption in the current BAL-002-1 standard (see section 1.5 of part D of the standard) does not require a previously declared emergency. If necessary, a declaration of an Energy Emergency Alert can be made ASAP ***after*** a restoration has failed to meet the Contingency Event Recovery Period requirement. The SDT agrees with your premise. Please refer to Requirement R1 Part 1.3.2 where the SDT excluded multiple events which exceeds MSSC.

Response:

David Kiguel - David Kiguel - 8 –

Answer Comment:

The SDT should be commended for its work in putting forward this draft. However, there are a number of areas where the draft can be improved before adoption by NERC.

1. R1.3 is confusing. Instead of detailing what the Responsible Entity must do, it extends to details on what is NOT subject to compliance. Results based standards must focus on what reliability objectives are to be achieved rather than what is not subject to compliance. All after "however, it is not subject to compliance with Requirement 1, part 1.1…." does not belong in the requirement. It could be part of the Compliance Section.
While the SDT appreciates your position, from past experience information contained outside of the requirement is not enforceable and cannot be used for determination of compliance. Therefore, any exclusions must be contained in the requirements.

2. Sub-Requirement R1.2 refers to documentation and as such is administrative in nature, i.e. does not contribute to Reliability. Furthermore, it seems to meet Criterion B4 of the Paragraph 81 Criteria.
The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

3. Requirement R3 seems to contain obligations that are related to/repeated

from R1. The obligation to restore Contingency Reserve should be merged into R1.

Response:

While the SDT appreciates your position, we believe that R3 is significantly different than R1. R1 requires an entity to recover from an event within a 15 minute window. R3 requires an entity to essentially modify their day-ahead plan to address the circumstance in the real-time and to address the next contingency if it were to occur. There is no expectation to carry reserves during the Contingency Reserve Restoration Period. Additionally, Requirement R3 carries forward the intent of the current BAL-002-1 Requirement R6.

Jeri Freimuth - APS - Arizona Public Service Co. - 3 –

Answer Comment:

R1.2. should not be included in the requirements section. This administrative function would violate FERC P81 as administrative in nature. Also, the process or form could change.

The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities subject to compliance utilize the same methodology for each event. There is not a reporting requirement in the standard.

R1.3. AZPS is concerned that the NERC Glossary of Terms only allows a BA or LSE to be in an EEA. And EOP-002-3.1 R7 and R8 have the Balancing Authority requesting to be declared in an EEA. If a Balancing Authority were in an RSG, that would make the RSG the Responsible Entity under BAL-002-

2. If the BA was experiencing and requested an EEA, does this transfer exception allowed in R1.3 to the RSG as not being subject to compliance?
If a Balancing Authority is experiencing an EEA event under which its contingency reserves have been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance. The RC should have gone through all steps prior to an EEA.

R2. If we understand correctly, this requirement is extending the requirement of EOP-011-1 R2 by reference. We do not believe it is advisable to include a requirement that adds to the elements of another requirement in a separate standard. It raises tangential questions such as "does this Operating Process have to be RC-approved as the Operating Plan does?"
There is no relation to EOP-011-1 R2. While this requirement does reference an Operating Plan, it is not the same Operating Plan referenced in EOP-011-1 R2. Instead, the Operating Plan referenced in BAL-002-2 may be the same Operating Plan required under R4 of TOP-002-4, specifically part 4.4.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 – WECC –

Answer Comment:

BPA is in agreement with the proposed standard. However, BPA believes there should be a clarifying comment in requirement R1. In R1, sub-requirement 1.1, following the second bullet, BPA would like the standard to state:

The recovery value for any Balancing Contingency Event(s) that occurs

Response:	***during the Contingency Event Recovery Period shall be the recovery value for the initial event.*** While the SDT understands your comment, there is no required recovery value for a Balancing Contingency Event in this standard. Recovery values are only used for Reportable Balancing Contingency Events. Please refer to CR Form 1 to determine how the recovery value is determined for multiple events.
Richard Vine - California ISO - 2 -	
Answer Comment:	1. The High VSL for R2 in the proposed BAL-002-2, as well as auditor guidance in the proposed BAL-002-2 RSAW, could be interpreted to require Contingency Reserve to be > MSSC at all times other than when deployed in response to a Balancing Contingency Event. However, in the Western Interconnection BAL-002-WECC-2 allows clock-hour averaging to determine if Contingency Reserves were adequately maintained. How will this apparent conflicting methodology be reconciled if BAL-002-2 is passed? The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting. The Contingency Reserve requirement in R2 is only for an Operating Process that determines and plans for Contingency Reserves. There should not be any real-time measurement for Contingency Reserves in R2, unlike in the WECC Regional Standard. Therefore, there is no conflict.

2. The definition of Contingency Reserve in the proposed BAL-002-2 indicates this is capacity that may be deployed to respond to a ***Balancing Contingency Event***. However, R3 states "Each Responsible Entity, following a ***Reportable Balancing Contingency Event***, shall restore Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period...". The proposed standard does not identify how long an entity has to return Contingency Reserve following deployment for a ***Balancing Contingency Event (i.e. -*** not "Reportable").

There is no recovery period required for a Balancing Contingency Event nor is there reserve restoration period associated with a Balancing Contingency Event. However, if a Reportable Balancing Contingency Event occurs the required time frame for reportable events will be reviewed to determine if the Balancing Contingency Event impacts the compliance responsibility. As an example, a Balancing Contingency Event that occurs two hours prior to a Reportable Balancing Contingency Event will not reduce the response requirement for the Reportable Balancing Contingency Event but a Balancing Contingency Event that occurs one hour prior to the Reportable Balancing Contingency Event may. Please refer to Requirement R1 Part 1.3.2.

Response:

Spencer Tacke - Modesto Irrigation District - 4 –

Answer Comment:

I am recommending a NO vote for the following reasons:

1. A specific percent change in ACE (Area Control Error) needs to be specified in the definition of ***Reportable Balancing Contingency Event***, where it states ***"…sudden decline in ACE based on EMS scan rate…"*** (on page 3).

	The reporting threshold is based on the size of the resource loss not the change in ACE. Therefore, no specific change in ACE is necessary. 2. Using arbitrary MW definitions for each major Interconnection (on page 4) under the same section on the definition of a ***Reportable Balancing Contingency Event***, may lead to inconsistent results, as the MW values actually needed are dynamic and based on the amount of load and on-line generation at the time of the disturbance or contingency event. The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on system frequency. Please refer to the Background Document posted with this standard. Your proposal would make it more difficult to determine the point at which an event becomes a Reportable Balancing Contingency Event. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance. 3. Under the ***Contingency Reserve Restoration Period*** definition on page 4, the ***period*** should be ***30 minutes*** instead of ***90 minutes*** in order to be consistent with the NERC TOP-004 (Transmission Operations) Standard. There is no direct coorelation between the time frames in the two standards. Your proposal would reduce the current restoration which has proven to provide an adequate level of reliability over the years. 4. Under ***the Rationale for Requirement R1*** on page 7, the phrase ***"..returns its Area Control Error (ACE) to defined values…"*** should include a locational reference to the actual ***defined values*** (i.e., what are they and where can they be found ?). The defined values are determined in Requirement R1 Part 1.1. The Rationale boxes are not enforceable and are moved to another area of the standard when the standard is filed.

	Thank you. Sincerely, Spencer Tacke Senior Electrical Engineer Modesto Irrigation District 209-526-7414
Response:	
Anthony Jablonski - ReliabilityFirst - 10 –	
Answer Comment:	**ReliabilityFirst votes in the Affirmative because the standard helps to better ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. ReliabilityFirst offers the following comments for consideration:** 1. Requirement R1, Part 1.3.1 i. There is a disconnect between the lead in Part 1.3.1 and the third bullet. The lead in states “the Responsible Entity is:” and the third bullet states “the Responsible Entity has depleted…”. As one can see, there is a

double use of the term "the Responsible Entity". RF recommends the following language for consideration:

1.3.1 the Responsible Entity:

• [is] experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and

• [is] utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

• has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

Response:

The SDT agrees with your comment and has modified the language.

Edward Magic - SCANA - South Carolina Electric and Gas Co. - 5 –

Answer Comment:

R 1.1.2 Reporting should not be a requirement.

R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event.

R2 M2 Contingency Reserves can and should be deployed for reasons to include loss of resources temporarily till mitigation measures are implemented less than MSSC. M2 does not make it clear that reserves can be used for any other resource loss less than MSSC. It appears you have to provide data that you had reserves >= MSSC each hour.

The BAL-002-2 RSAW posted further supports our primary concern “Review the evidence and verify that the entity had available Contingency reserves equal to, or greater than its Most Severe Single Contingency” Suggest the wording be revised “Confirm the applicable Entity met the Contingency Requirement for Reportable Balancing Contingency Event(s)”

The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting. Further Requirement R2 and Measure M2 have no bearing on utilization of Contingency Reserve. Rather it is only a requirement to plan to have Contingency Reserve as part of you Operating Plan.

Response:

Joseph Bencomo - LG&E and KU Energy LLC - 1,3,5,6 - SERC,RFC -

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6

Answer Comment:	These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): LG&E and KU Energy, LLC and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RFC and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. **Comments** Clarity is needed as to whether or if a BA that is a member of an RSG but does not request RSG assistance for a specific BCE is considered the Responsible Entity. The "active status" language used in 4.1.1.1 is unclear. **Suggested solution** – Modify language in 4.1.1.1 to: 4.1.1.1. A Balancing Authority that is not a member of a NERC registered Reserve Sharing Group is the Responsible Entity. The SDT appreciates your comment. However, the proposed language provides the flexibility for RSGs to allow members to participate on an event-by-event basis as some RSGs currently allow. The proposed draft 7 requires reporting and compliance evaluation of each individual Reportable BCE. Quarterly reporting and evaluation of Reportable Events on a quarterly basis has worked well and should be continued. The proposed standard does not require any reporting. The language as drafted is proposed to address a directive from FERC Order 693 Paragraph 354 which requires compliance based on individual events. BAL-001-2 becomes enforceable 7/1/2016, R2 (BAAL performance) will incent the appropriate BA/RSG action to a Reportable BCE without forcing

action that could be contrary to interconnect frequency stability. BAL-001-2 has negated the need for BAL-002-2.
Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

The language in R1.3 related to an exemption from R1.1 needs to be applicable to R1 and R3.

An entity experiencing an EEA (or any of the other exemption scenarios in R1.3) should not be required to restore ACE as stated in R1.1, document the Reportable BCE as per 1.2 or restore Contingency Reserves to MSSC within the Contingency Restoration Period as stated in R3.

For a Responsible Entity experiencing an EEA, compliance with BAL-002-2 R3 is not consistent with actions required under the EEA.

Suggested solution – Modify language in 1.3 to:

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 parts 1.1 and 1.2 and R3 if:
The entity experiencing any of the scenarios in Requirement R1 Part 1.3 is exempt from compliance for Requirement R1 Part 1.1.

The exemption in Requirement R1 Part 1.3 is applicable only to Requirement R1 Part 1.1. Entities that experience events that meet the exemption for

Requirement R1 Part 1.1 should still be able to document the Reportable Balancing Contingency Event s under Part 1.2. The definition of Contingency Reserve addresses your concern related to Requirement R3 by allowing firm load readied to be removed from the system, thus allowing the load to count as Contingency Reserve.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 – NPCC -

Group Name: NPCC--Project 2010-14.1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1

Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Answer Comment:

With the requirements as written, the Responsible Entity should include the Reliability Coordinator. As defined in the NERC Reliability Functional Model Version 5 for the Reliability Coordinator, **Balancing operations**:

"**Balancing operations.** The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability."

The SDT does not believe that this standard should include any requirements on the Reliability Coordinator. The Reliability Coordinator is governed by requirements located in the IRO standards.

Consider incorporating Requirement R3 into Requirement R1 by adding the following Part 1.4:

1.4 Restore its Contingency Reserve to at least its Most Severe Single Contingency before the end of the Contingency Reserve Restoration Period.

The SDT discussed this and determined that the restoration of ACE and the restoration of Contingency Reserve are two separate and distinct actions. Therefore the SDT believes that these two actions should be covered under two separate requirements.

Regarding the wording used to define the **Most Severe Single Contingency (MSSC),** as it reads now the MSSC is defined as "The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss ...".

	The process used to find the MSSC uses system models and does allow the modelling of contingencies. For clarity, suggest revising the wording in the definition. The models themselves neither identify contingencies nor are contingencies “maintained in” them. Suggest eliminating the words “…as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group…”or replacing the words “identified and maintained in the system models within” with the following: “identified using system models maintained within…”. The SDT has made the necessary modifications. We feel the time requirement to declare an EEA of any level prior to 1.1 being waived is an unnecessary operations burden during the Contingency Event Recovery Period. It could result in an entity being non-compliant because complete recovery is delayed by the time it takes to go through the "declaration" process. We feel the new standard is adding an exposure to non-compliance because of the need for the RC to declare an emergency prior to the waiver of the ACE correction requirement in Part 1.1. Within NPCC there are entities that fill both the RC role that declares the EOP-002-3 Energy Emergency Alert level, and the BA role that BAL-002-2 will apply to. The SDT believes that the proposed requirement under Requirement R1, Part 1.1 is not an undue burden because the use of an EEA is not applicable to this standard and is not appropriate as a solution for complying with Requirement R1 Part 1.1. If an entity is not in the EEA prior to a loss, the waiver of R1 Part 1.1 would not apply. In addition, the wording in the third bullet of Part 1.3.1 (Part 1.3.1 needs identification in the draft) needs clarification. For example, if your MSSC is a resource loss of 400 MW, this Part’s wording would suggest that the depletion of "Contingency Reserve to a level below its Most Severe Single Contingency" would refer to a value of less than 400 MW. You might deplete

your reserves by 250 MW and still have 150 MW remaining to meet another contingency after the initial event which may be sufficient and not require a waiver. We suspect that the intention is that all of the MSSC determined value of required reserve is depleted before the waiver is allowed.

The intention of the bullet is that if an entity utilizes its Contingency Reserve such that it dips below its MSSC, regardless of the magnitude, the entity can no longer fully respond to meet Requirement R1 if its MSSC occurs. Therefore, Requirement R1 Part 1.3.1 allows an exemption from compliance if all of the three bullets are occurring at the same time.

Response:

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 – SPP –

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Carl Stelly	Southwest Power Pool Inc	SPP	2
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
Jes Gray	Omaha Public Power District	MRO	1,3,5

Answer Comment:

We would suggest to the drafting teams developing coordinated efforts with the Alignment of Terms Standards Draft Team (Project 2015-04). The collaborative efforts would pertain to the revised and newly proposed terms in BAL-002-2 which would help ensure that these terms are included in both the NERC Glossary of Terms as well as the Rules of Procedure for proper alignment (which can be addressed in Phase II of their project). Of course, this collaborative effort would take place once NERC's BoT and FERC approves the proposed terms and standard pertaining to this current project. If a proposed definition is also in the Rules of Procedure, the drafting team will work with NERC to ensure that alignment is maintained going forward.

Our review group also noticed that the drafting team uses the acronym 'RE' several times (second paragraph on page 4) in the Rationale for Contingency Reserve Definition section of the standard. We will make the assumption that you are referring to the term 'Responsible Entity'. However, we would suggest either using it as an appositive with the term or removing it from the document completely. We feel that some confusion will arise amongst the industry on what 'RE' is being referred to. For example, 'RE' could refer to 'Regional Entity' or 'Registered Entity'.
The SDT has made the appropriate modifications.

In the Rationale section for Requirement R1, the drafting team mentions "The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language". We would ask the drafting team to provide more clarity on what direction BAL-002-2 is going in reference to the EEA. The rationale states that the drafting team has developed proposed language. Can we assume this proposed language is currently in the standard and if so, will this language match up with the NERC's process changes to the EEA levels (which hasn't been developed yet)? The next question would be….will these process changes be vetted through the voting process or will it be the law of the land?

The SDT has made the necessary clarification to the Rationale Box. Please note that the proposed EEA changes were developed as part of the EOP-011-1 standard currently filed at FERC.

Our group understands that the conversation pertaining to the retirement of BAL-002-2 is in the distant future. However, we have the concern that there are current documentation in place that helps serve the industries needs in reference to the MSSC. With that being said, we feel that BAL-002-2 brings confusion and redundancy to the industry and we would suggest that the drafting team take into consideration the retirement of this standard.
Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Finally, we would like to suggest to the drafting team once the terms and standards have been approved by the NERC BoT and FERC to follow up on this project and ensure that the RSAW be properly aligned with this standard.
The SDT agrees that the RSAW could be interpreted in such a manner to not meet the intent of the requirement. The RSAW is being modified to clarify the necessary compliance elements for the next posting.

Response:

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 – RFC -

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Christina V. Bigelow	ERCOT	TRE	2
Ali Miremadi	CAISO	WECC	2

Answer Comment:

The SRC agrees with the intention of the SDT draft 7 posting to:

· Provide the risk based parameters (ACE range, Recovery period, Restoration period) for responding to a Balancing Contingency Event (BCE);

· Ensure that the definition of Most Severe Single Contingency (MSSC) does not include more than one resource;

· Ensure that the definition of BCE does recognize the possibility of the loss of more than one resource;

· Eliminate draft 6's hourly obligations; and

· Clarify that shedding load is not an expected action in order to maintain reserves.

The SRC does not agree with proposed standard wording that:

· Links MSSC to BCE; and

- Links Contingency Reserves (CR) to Disturbance Control Standard (DCS) compliance.

The SRC proposes clarifying modifications to definitions for:

- Balancing Contingency Events;
- MSSC;
- Contingency Event Recovery Period; and
- The EEA level referenced in R1.3.1

The SRC again asks the SDT to remove the language within draft 7's proposed CR requirement that ties DCS compliance to the use of CR.

The SRC has characterized its comments in three classifications: those proposed to facilitate clarity; those proposed to ensure that the focus of requirements remains on reliability; and those proposed to address other concerns.

Revisions Proposed To Facilitate Clarity

The SRC would ask that the SDT to redraft the requirements in more direct terms. Phrases like "demonstrate recovery" in the requirement section of the standard can be construed ambiguously and a clear reliability requirement omits unnecessary words and directly defines the obligation.

In particular, the SRC suggests that the linkage between R 1.1 and R1.31 is a source of ambiguity within the standard because:

· Requirement R1.1 defines the target ACE correction (range of recovery);

· Requirement R1.3 defines Contingency Reserve deployment;

· Sub-Requirements of R 1.3 then introduce exceptions for **R1.1** (*i.e.*, R 1.3.1 and R 1.3.2).

This organization does not allow readers and entities responsible for compliance and direct correlation between specific defined obligations and the proposed exemptions. To facilitate clarity, the SRC offers two recommendations. The first recommendation preserves much of the current, draft language while the second recommendation provides more streamlined language:

1. *Retaining current draft language:*

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

• zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

	or, • its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event. **1.2.** document all Reportable Balancing Contingency Events using CR Form 1. **1.3.** deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if: **1.3.1** the Responsible Entity is: Unless: · the responsible entity: • is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher; is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan; or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency . or, · the following subsequent event(s) occur: **1.3.2** the Responsible Entity experiences:

• multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Even;, or

• multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

1. *More direct version*:

R1. Unless the Responsible Entity is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher, is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, , the Responsible Entity experiencing a *Reportable Balancing Contingency Event* (RBCE) shall return its ACE to:

· Zero within the *Contingency Event Recovery Period* if the Responsible Entity's Pre-RBCE ACE Value were positive or equal to zero; or

· Its Pre-RBCE ACE Value if the Responsible Entity's Pre-RBCE ACE Value were negative

Where a Balancing Contingency Event exceeds the responsible entity's MSSC or multiple Balancing Contingency Events occur within the Contingency Event *Restoration period* of the 1st RBCE, the responsible entity shall deploy contingency reserves, but such response shall not be subject to Requirement R1:

Revisions proposed to ensure that the focus of requirements remains on reliability

The SRC asserts that the primary focus of BAL-002 should be reliability (ACE recovery) with less focus be given to the specific process regarding how to meet the reliability requirement. The current draft appears to link economic sharing arrangements (Contingency Reserves) to a reliability requirement and, therefore, precludes the use of more effective processes to meet the reliability requirement. The SRC cautions the SDT against mandating the use of a process where such usage would be inappropriate from both a reliability and cost efficiency perspective when other processes are available For example, as written, draft 7 could preclude the use of Demand Side Management (DSM) as Contingency Reserves (in contradiction of Order 1000), and restricting DSM to Emergencies only. For these reasons, the requirements should be re-focused on what needs to occur for reliability – not how such activities are performed.

The SRC does recognize the SDT's attempt to address the issue of maintaining reserves designed to preserve serving load verses the issue of shedding load to preserve reserves and that it makes no sense to shed load to maintain reserves that are designed to protect load from being shed.   Additionally, the SRC questions the need for the proposed Requirement R2 (*i.e.*, the requirement to have a method to compute MSSC). Such

requirement is administrative in nature as it mandates a creation of a procedure, an implementation process for that procedure, as well as a mandate to "have" a market service to calculate MSSC. The sentence in draft 7 can be read as ether:

· an annual obligation to compute MSSC and to use that annually-

	computed MSSC in system operations, and · carry an equivalent amount of reserves for that year or · develop a plan to explain how to compute MSSC and review that plan every year · implement the computation (the implication is that the plan will introduce the time frame for updating MSSC) · carry an equivalent amount of RC (for as long as the plan states) The definition of MSSC is axiomatic and does not require a formal procedure. The only plausible justification for having such a plan is mandate self-imposed rules regarding when to compute MSSC; how to apply that calculation; and for how long. Given the ambiguity in draft 7's R2, either approach can be justified. Such ambiguity would not serve reliability. As an example, if draft 7 really did intend linking MSSC to an annual value, and in doing so lock-in a minimum reporting value (80% of MSSC), then what could occur is that small BAs can have a minimum reportable value that is larger than any unit that is operating on a given day – in effect - exempting them from ever reporting. On the other hand, if draft 7 really did intend to provide flexibility to the BAs, a number of questions arise: Is this a daily scheduling function, or a continuous operating function? Is the objective fixed or does it depend on what is operating at the given time? Accordingly, the current approach could be interpreted broadly and variably and should be revised as it does not appear to be directly focused on or facilitating reliability.

	Revisions Proposed to Address Other Concerns The SRC suggests the following comments and/or revisions for the SDT's consideration: 1. Delete the phrase "within system constraints" in Requirement R1. Because BAs are not responsible for system constraints (that's the role of TOP), the inclusion of this phrase connotes that a BA can be held responsible for exacerbating a SOL problem, even if the BA had no knowledge of the limit and was taking actions to comply with its obligations. The requirements should respect current roles and responsibilities of the various functions and, currently, the TOP is responsible for directing the BA in this regard. 2. The standard has a reporting requirement, but does not include a reporting timeframe. Therefore, the most conservative assumption would be that reporting is on and "individual event" basis. For draft 7, the SDT rejected quarterly reporting based on a non-relevant paragraph in Order 693. 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters. The SRC requests that the SDT explain its correlation between the reporting requirement and P 354 and requests that the SDT clarify the timing of any required reporting. Additionally, the SRC is unclear as to how "the VSL levels

	developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure." Upon review, it appears that values for entities are calculated on a % of recovery whether applied to an individual event or quarterly performance – accordingly the severity of a violation would still be correlated to overall performance for some time period. The SRC requests that the SDT re-evaluate its explanation and provide additional clarification. 1. The Draft 7 definitions of MSSC and BCE do not resolve the issue of BCE being greater than the MSSC because Draft 7 continues to link the definitions of MSSC and BCE. The SRC believes MSSC is an a priori / actual state value while BCE is an a posteriori event/experience. The SRC agrees with the SDT that MSSC can never be more than one resource otherwise it would not be a "single contingency." BCE on the other hand can (as the current definition indicates) include the impacts of the loss of more than one resource. To address this concern, the SRC offers the following comments and revisions. Draft 7 definition of MSSC: **Most Severe Single Contingency (MSSC):** The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority). Draft 7 definition of Event:

	Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE. Given the above definitions, the SRC concludes that the SDT correctly wants to ensure that MSSC include large interchange schedule imports as well as large generators. The definition of BCE does that (see sub item B). The draft 7 definition of MSSC relies on the definition of BCE to ensure that such interchange gets considered. The problem is that the foreword of the BCE definition includes the phrase "or any series of such otherwise single events." That addition makes it virtually impossible to quantify / limit one single

	resource amount for an MSSC. The SRC would suggest that Draft 7 definition of Event be retained, but that the definition of MSSC be redrafted. The SRC suggests: MSSC is the MW capacity of the single largest resource scheduled to operate for a given day's peak load. The resource may be a generator (Maximum Continuous Operating Capacity) or a Firm Interchange scheduled import. This revision: · Changes the MSSC definition from being linked to a Balancing Contingency Event of undefined size, to linking MSSC to an easily identified single resource capacity/expectation. · Can be used to provide clarity concerning why and how the amount of CR can be set to a daily MSSC; and how and why every CBE can be "reported" upon without being subject to the DCS objectives for an MSSC. The Draft 7 definition CR does not define what CR is, but rather defines what CR may be used for. Moreover, the definition's use of the phrase "provision of capacity" requires further explanation to clearly delineate between the concept of "provision of capacity" in the Operating Planning environment (meaning to request that resource be made available to serve load) versus the "provision of capacity" in the compliance/operating environment (meaning the amount of energy that was produced at the request of the BA). An additional issue with the first sentence is that, as written, it specifically excludes the use of those reserves to serve firm customer load. To address this concern, the SRC offers the following comments and revisions.

Draft 7 definition of Contingency Reserves

Draft 7 definition of Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The SRC suggests that the issue of CR and reserves in general requires an Industry-wide review; and the SDT in its introduction to its Response to Comments propose the ERO conduct such a review prior to making a decision on a final ballot. The review would be used to decide if:

· Reserves were linked to day ahead scheduling in the sense that “reserve” capacity over and above the capacity scheduled to meet a peak load. This concept was referenced in the original Policy 1 – Generation Control and Performance, (dated Feb 1, 1997) at romanette ([i]) If CR were viewed as scheduled available system capacity there would be no issue, because then the measurement of reserves would be focused on the planned capacity for the day. Once that capacity is synchronized it can be used for any and all purposes.

Response: **Please refer to the response to these comments at Page 76.**

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:

We would like to thank the SDT for their work on this proposed revision to BAL-002-1 and the opportunity to provide comments.

Definitions

MSSC: As written the MSSC definition is linked to and dependent on the definition of a Balancing Contingency Event. In doing so an RE must determine its MSSC based on a Balancing Contingency Event, or series of events including imports, separated by one minute, that have not occurred. As long as the definition of MSSC is dependent on the definition of a BCE, we suggest that MSSC is incalculable and propose the change below.

Most Severe Single Contingency (MSSC): The loss of a single Element as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, or the sudden loss of an import, or the sudden restoration of a Demand that was used as a resource, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

The SDT does not believe that your structural changes provides any additional clarity to the proposed definition to the proposed definition.

Contingency Reserve: As written, the criteria for allowing readiness to reduce Firm Demand in Contingency Reserve is ambiguous. We suggest adding clarifying language to clearly state when the readiness to reduce Firm Demand will be accepted as Contingency Reserve.

We propose the following changes for clarity.

Contingency Reserve: The resource capacity, measured in MW, above that serving Firm Demand, that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

• is experiencing a Reliability Coordinator declared Energy Emergency Alert level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
The SDT believes that your suggested modification to the first bullet appears to duplicate the second bullet while adding a potential burden to compliance.

Requirement 1:

We understand the intent of the SDT, however, R1.3 states that an RE must deploy Contingency Reserve for all Report Balancing Contingency Events regardless of whether there is a need to deploy Contingency Reserve to comply with R1.1. Recovery is often accomplished through frequency responsive and regulation resources. Additionally, R1.3 as written could be

	interpreted to mean that an RE shall deploy ALL available Contingency Reserve, which could be well above MSSC, for ALL Reportable Balancing Contingency Events which could have an adverse impact on Interconnection frequency and BES reliability. For example, using the PJM minimum synchronized reserve requirements (100% of MSSC, or approximately 1400MW deployed via All-Call) and regulating reserves (+/- 700MW during peak hours); language that suggests a mandatory deployment of Contingency Reserve could result in well over 2100MW, responding to a 900MW reportable event. This response could be much higher since synchronized reserves are typically much greater than the 1400MW requirement and regulation alone could result in 1400MW of response. We also recognize that the BAAL limits defined in the recently approved BAL-001-2 ensure that an RE will take all available actions to respond to a Reportable Balancing Contingency Event and support Interconnection frequency. For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished. Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated. Additionally, we suggest that the phrase "within system constraints" should be removed because BA's are not responsible for system constraints; that being the role of the TOP. The TOP standards address system constraints and the TOP is responsible for directing the BA in this regard.

Accordingly, we propose the changes below.

1.3. respond to all Reportable Balancing Contingency Events, which may include the deployment of Contingency Reserve, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity is:

• experiencing a Reliability Coordinator declared Energy Emergency Alert Level where an energy deficient BA is not able to maintain minimum Contingency Reserve requirements, and

• utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and

• the Responsible Entity has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

The drafting team agrees the BA is not responsible for determination of system constraints. However, the following selected list of Requirements from Standards, either currently enforceable or approved by the NERC Ballot Body, NERC Board of Trustees and filed at FERC requesting approval for future enforcement, makes it clear that a Balancing Authority can't perform their duties reliably without being knowledgeable of system constraints.

TOP-001-3 R20
TOP-002-2.1b R4, R5, R6, R7, R9 and R10
TOP-002-4 R4
TOP-003-1 R1.2

TOP-003-3 R2, R4 and R5

Finally, removing the phrase would make a requirement to activate all Contingency Reserves, regardless of any negative impacts to the Bulk Electric System for large events. The drafting team discussed this concern and determined that the BA should only activate the level of reserves that could be safely used without creating reliability issues on the grid.

Requirement 2:

We propose the following changes to Requirement 2 to add clarity.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have available Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
The SDT has made this clarifying modification.

Requirement 3:

With the addition of Requirement 3, either R1.2 should be removed from the standard or the CR Form 1 should be modified to demonstrate Contingency Reserve restoration including subsequent Balancing Contingency Events that may occur within the Contingency Event Restoration Period so that compliance to a Reportable Balancing Contingency Event can be demonstrated with a single document.
Thank for your suggestion. The SDT believes that compliance with Requirement R1 and compliance with Requirement R3 are two different

actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods.

Response:

Kathleen Goodman - Kathleen Goodman On Behalf of: Michael Puscas, ISO New England, Inc., 2 -

Answer Comment:

ISO New England does not agree with the SDT's position that an EEA Level 3 is necessary in order to support an exemption from R1. If this were elevated to Level 3 that would imply shedding load in order to maintain reserves and ISO New England understands that this was not the intent.

EOP-011 states that a Level 2 EEA is "The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority." meaning all available resources are in use serving load; and " An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements." which given the first instance can only be accomplished through arming for load shed to cover the reserves if a contingency were to occur. In the alternative, this would mean shedding actual customer load to maintain reserves before the contingency actually occurs, which is not in the best interest of Reliability.

The SDT disagrees with your comment. EEA Level 3 is titled “Firm Load interruption is imminent or in progress”. The SDT believes that if an entity is utilizing firm load for its Contingency Reserve then interruption of firm load is imminent. Therefore, an entity utilizing firm load for Contingency Reserve would be in an EEA Level 3.

Response:

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 –

Answer Comment:

ERCOT commends the drafting team on their efforts to improve BAL-002-2. However, it has concerns and recommendations regarding the proposed modifications. ERCOT supports and incorporates into its comments by reference the comments submitted by the ISO/RTO Council Standards Review Committee. Additional concerns and recommendations are described below by Requirement. Proposed revisions are *italicized*.

Please refer to our response to the ISO/RTO Council Standards Review Committee, beginning on page. 76.

1. Definitions – ERCOT reiterates its previous comments regarding the Reportable Balancing Contingency Event thresholds contained within the definition of a Reportable Balancing Contingency Event. ERCOT believes that the introduction of various, differing thresholds creates unnecessary complexity and would propose a 1000 MW threshold for its interconnection as such threshold aligns with the current practice. Further, ERCOT reports other, smaller events to NERC and its Regional Entity through different mechanisms and, therefore, with differing reporting thresholds, the same event can be reported to NERC multiple times under different requirements. Accordingly, since the threshold limits relate only to reporting and associated documentation, ERCOT respectfully submits that lowering the reportable event thresholds does not provide any benefit to reliability.

The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on system frequency. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance. Please refer to the Background Document posted with this standard.

	2. ERCOT reiterates the need to revise Requirement 1 to provide obligations in more direct terms and with additional clarity and reiterates its comments regarding burdensome and administrative nature of the individual reporting requirement contained within Requirement R1.2 for individual Reportable Balancing Contingency Events. Such reporting does not benefit reliability and could obscure trends or other characteristics that would be obviated by reporting over a longer time period. Perhaps the SDT could consider a time period that is shorter than quarterly, but clarify that reporting is not on an individual basis triggered by individual events. R1 part 1.2 does not require a report to be submitted. Instead it requires the calculation to be on the referenced form. This ensures all entities subject to compliance utilize the same methodology for each event. The SDT disagrees with the inclusion of a quarterly report in a standard. Adding a requirement for quarterly or any other time period for reporting would be a Paragraph 81 issue. If NERC or the Regions desire quarterly reporting it should be done under their data collection process. 3. Requirement R2 –ERCOT respectfully submits that, as proposed, Requirement R2 adds potentially onerous and unnecessary administrative processes and documentation to what has, historically, been a simple, well-established process regarding identification of the MSSC and the procurement of appropriate contingency reserves. To simplify this requirement while retaining the reliability-related aspects of its objective, ERCOT offers the following revisions for the SDT's consideration: *Each Responsible Entity shall document and implement its criteria for identification of MSSC and its processes for review of MSSC and for procurement of contingency reserves greater than or equal to the identified MSSC, which shall be reviewed no less than annually.*

Measure 2 could then be modified as follows:

Compliance may be achieved by demonstrating that:

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

• *Criteria for determination of the MSSC;*

• Documentation of its processes for identification of the MSSC and procurement of contingency reserves equal to or greater than its Most Severe Single Contingency; and

· Evidence to indicate that the processes have been reviewed and maintained annually.

ERCOT suggests this alternative because the identification of MSSC is subject to criteria and are part of an overall process to be performed. Further, the proposed requirement presumes a particular structure for responsible entity's compliance processes and procedures that designates the "how" of meeting the requirement instead of the "what." The proposed revision preserves the objective of the proposed Requirement 2 while ensuring that the requirement is results-based and respectful of the various administrative structures established within various entities to administer compliance-related documentation and processes.

The SDT does not believe that the requirement is telling an entity how to comply but rather requiring a process to address the reliability issue. Also, the SDT has modified the requirement to provide additional clarity.

ERCOT thanks you for the opportunity to comment upon the proposed

Revisions to BAL-002-2. Should the ERO wish to provide additional guidance regarding the mix or management of Contingency Reserves, it should consider the development and publication of a Reliability Guideline.

The SDT thanks you for your suggestion. The SDT has developed an Operating Reserve Guideline approved through the NERC OC. The guideline document can be found at the following link. http://www.nerc.com/comm/OC/Pages/Reliability-Guidelines.aspx

Response:

Ben Engelby - ACES Power Marketing - 6 –

Group Name: ACES Standards Collaborators - BARC Project

Group Member Name	Entity	Region	Segments
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Answer Comment:

(1) We applaud the SDT on its efforts to clarify the language of the standard and respond to our previous comments. We continue to believe the SDT is heading in the correct direction during the development of this

	standard. However, we still have concerns regarding the language, scope, and implementation plan. Thank you (2) We are disappointed that the SDT has not responded or addressed our previous concerns regarding the "Most Severe Single Contingency" definition. From the definition, we believe the applicability reference should be removed entirely. We recommend the definition should read "A Balancing Contingency Event, as identified by the Responsibility Entity and maintained in its system models, that would result in the greatest loss of resource output at the time to meet Firm Demand and export obligations, excluding those export obligations for which Contingency Reserve obligations are being met by a Sink Balancing Authority." We also recommend the removal of the MW measurement, a unit of power, as a Balancing Contingency Event is a moment in time. The term Responsible Entity is not defined in the glossary and therefore cannot be used in the definition. The drafting team also believes that the measurement in MWs is appropriate in that the process uses MWs to determine the amount of loss for a DCS event. There was no other proposed means to measure the event so it is unclear what would be measured without using MWs. For these reasons, the SDT has not made the suggested changes. (3) Likewise, we wish the SDT would further clarify this standard's applicability. We understand the need to address the instance when a BA fails to meet the membership requirements of a Reserve Sharing Group (RSG). We recommend that Section 4.1.1.1 should be split as follows, "4.1.1.1 A Balancing Authority is the Responsible Entity that is not a member of a Reserve Sharing Group" and "4.1.1.2 A Balancing Authority that is a

member of a Reserve Sharing Group and 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 Reserve Sharing Group."

Some RSGs allow for members to participate in the group on an event-by-event basis. As drafted the language is more specific than that proposed. Therefore, the SDT has not accepted the proposed modification.

(4) The SDT needs to address our previous comments regarding the "Reportable Balancing Contingency Event" definition. We recommend the removal of "Prior to any given calendar quarter..." from the definition, as it implies the need for an additional requirement for Responsible Entities to coordinate an exception from the rest of the definition which is based on a percentage of the MSSC or an Interconnection-based amount. Furthermore, we continue to believe that the thresholds in the definition are arbitrary, and ask that the drafting team provide a technical basis for these values. In many cases, the values selected are below the median values identified in Attachment 1 of the background document. By not documenting the more frequently occurring values annually, we fear this could cause issue later on in the standard development process. We recommend moving the identification of these values, and supporting background for their selection, to an attachment within the standard, similar to the approach taken in NERC Standard BAL-001-2.

The SDT disagrees with removing the language related to changing the reportable threshold from the definition. Without that language, it would prohibit any modification from the 80 percent of MSSC. The drafting team believes that any modification to the reporting threshold must be made prior to the event, not after the event. In order to determine the appropriate reportable threshold, documentation is necessary if an entity decides to change this threshold.

The reporting thresholds are supported by the referenced background document. With the reference to the background document, the commenter should understand that the values are not arbitrary but determined by the statistical evaluation of historical events. Once the evaluation was done, the drafting team determined the average of the medians and determined that the values should be rounded to an even 100 value to make the reporting threshold easily remembered by operating personnel.

(5) Under certain situations, a Responsible Entity may not be aware of the significance of a Balancing Contingency Event. For the definition of Contingency Event Recovery Period, the SDT should clarify that the recovery period should not start with the initial decline of resource output, but the instance when ACE reaches the reportable threshold of a Reportable Balancing Contingency Event and fifteen minutes thereafter.

There is not an ACE threshold for a reportable event. The reportable event is established by the amount of the resource loss. As an example, if a runback occurred and the MW threshold is not reached in a single minute then it would not be considered a reportable event. Therefore, the start of the event would be the minute in which the threshold is met not the start of the runback.

(6) The SDT should consider moving all standard-specific definitions to the NERC Glossary of Terms.

Once the standard is adopted by the NERC BOT, the definitions would be moved to the NERC Glossary of Terms.

(7) We feel the SDT is overcomplicating the language of Requirement R1. We concur that clarification is needed in the instance when a Balancing Contingency Event follows a single Reportable Balancing Contingency

	Event. However, embedding a reference to identify what is and isn't required within the same requirement is cumbersome. We recommend moving the embedded reference to another requirement and identify the Contingency Event Recovery Period only applies to a single event. While the SDT understands your concern we do not agree with the desire to separate this into two requirements. Separation of Requirement R1 into two requirements would likely cause a violation of one requirement that could result in violation of both requirements. (8) We have concerns with the VSLs identified for Requirement R1. We agree with the SDT's conclusions that the measured contingency reserve response and required recovery value of Reporting ACE, when is adjusted for other Balancing Contingency Events that occur during the Contingency Event Recovery Period, are mathematically equivalent. However, the VSLs are based on one approach while the spreadsheet is based on the other. We recommend the SDT select one approach and use it consistently throughout the standard. The SDT reviewed the VSL and CR Form 1 calculations and find them to be consistent. Therefore, no changes have been made to either the VSLs or CR Form 1. (9) We acknowledge the SDT for its response to our previous comments regarding Requirement R1.2. However, we still feel that a requirement for documenting events in a spreadsheet is administrative in nature, and could even be classified as a P81 requirement, as its violation would never result in a harm to BES reliability, especially at a Medium level risk to operations. If an entity only identifies the MW loss and date and time of the event, yet leaves the rest of the form blank, would this result in a violation? As written, the answer would be no, although an incomplete form would not meet the

intention of the SDT to provide consistent reporting. We recommend the SDT identify the criteria needed for uniform reporting in a separate attachment to the standard and remove administrative tasks that meet Paragraph 81 criteria.

The SDT disagrees with the characterization that this is a Paragraph 81 issue. The Requirement R1 part 1.2 requires a specific calculation in the form. This ensures all entities utilize the same methodology for each event. There is not a reporting requirement in the standard.

The SDT believes that a form that is partially filled out may be sufficient to meet compliance with Requirement R1 Part 1.2, although this would depend on circumstances. However, an incomplete form will show a failure to correct ACE to its pre-event level which would be a violation of Requirement R1 Part 1.1.

The SDT disagrees with moving the criteria to a separate attachment and having the entities create their own calculation of compliance. This would put every entity at risk of violation due to the need to support the calculation made to demonstrate compliance prior to any compliance evaluation. By providing the form referenced in Requirement R1 Part 1.2, industry essentially needs to provide one number from the form to prove compliance.

(10) We recommend the removal of "all Reportable Balancing Contingency Events" as a condition listed in Requirement R1.3. This condition is already referenced in R1. We believe rewording Requirement R1.3 to read "…deploy Contingency Reserve, within system constraints, except when not subject to compliance with Requirement R1 part 1.1 if…" would still satisfy the requirement.

For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished.

	Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated. (11) In reference to Requirement R2, we question the need to review an Operating Plan, as such action is already implied with an Entity is "maintaining" their plan. We believe the language identified should be aligned with the language listed within NERC Standard EOP-010-1. The SDT appreciates your comment but believes that use of both words provides an additional level of clarity. We agree that it is possible to accomplish both with one action. (12) If the intent of the SDT to have Responsible Entities use CR Form 1, then we recommend adding its use in Measure M3 and in the RSAW for R3. A Responsible Entity is already able to use the form to demonstrate its deployment of Contingency Reserve, within system constraints, then it should be able to reuse the form to demonstrate the restoration of Contingency Reserve within the Contingency Reserve Restoration Period. Thank for your suggestion. The SDT believes that compliance with Requirement R1 and compliance with Requirement R3 are two different actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods. (13) We disagree with the VSLs identified for Requirement R3 that measure the percentage of Contingency Reserve restoration. The requirement identifies the required time that such restoration must be completed. We recommend replacing with the form "The Responsible Entity restored less

	than x% but at least y% of required Contingency Reserve following the conclusion of the Contingency Event Restoration Period." The SDT believes that your suggested wording allows unlimited time for an entity to restore its Contingency Reserve. (14) We feel that the bullets of Requirement R1.1 and Requirement R3 are redundant in reference to "any Balancing Contingency Event that occurs during the Contingency Event Recovery Period." We suggest removing the redundant bullets in Requirement R1.1 for clarity, and instead expand Requirement R3 to include a reference to magnitude. The SDT believes the removal of the bullets would require an entity to recover its ACE within 15 minutes regardless of other events occurring within that 15 minutes. The SDT also believes that compliance with Requirement R1 and compliance with Requirement R3 are two different actions. Requirement R1 requires a specific calculation methodology. Requirement R3 compliance may be demonstrated with various methods. (15) We caution the SDT that references to the term "Reporting Area Control Error" in the rationale for Requirement R1 goes into effect July 1, 2016. The Implementation Plan references that the standard would go into effect six months after FERC approval. Since this term is critical to the definition of "Pre-Reporting Contingency Event ACE Value", we recommend an update to the Implementation Plan to July 1, 2016 or later as the effective date. The SDT understand your concern. However, based on our review of the timing, this is not an issue. (16) We observe a typographical error within the Implementation Plan

regarding the definition of Most Severe Single Contingency. We recommend the removal of the "that is not part of a Res area" reference. The definition should then read "…within the Reserve Sharing Group (RSG) or a Balancing Authority's area that not part of a Reserve Sharing Group…"

Thank you. The SDT has made the necessary correction.

(17) We recommend the SDT fix the title page of the background document to include the document's title, "Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event Standard Background Document."

Thank you for your comment. The title was lost during the translation to a PDF document. The SDT will make the necessary correction.

(18) We thank the SDT for this opportunity to comment on this standard.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 –

Answer Comment:

Texas RE noticed the VSL for R1 does not address R1.3. The language for R1.3 should be included.
Requirement R1 Part 1.3 defines exceptions; therefore the SDT does not believe that it would be appropriate to create a VSL.

Texas RE noticed the VSL for R2 does not address the review annually portion of the Requirement. VSL should be changed to include "maintain annually".

The SDT has modified the lower VSL to clarify that "maintain" meant "maintain annually".

Texas RE recommends the VSL for R3 should include Requirement language "at least its Most Severe Single Contingency".
The SDT believes that as written ("…required Contingency Reserve…") the VSL provides sufficient clarity.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 –

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a BA to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency.

Example of loss of generation in the middle of the night:

If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response required by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Response:

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 – FRCC-

Answer Comment:

Now that BAL-001-2 is approved, there will be another standard driving a Balancing Authority to take corrective action in certain situations where compliance with BAL-002 may have a detrimental impact on Interconnection frequency. One example would be if there is a loss of generation in the middle of the night. If the Reportable Disturbance occurs when frequency is above Scheduled Frequency, as over-response by the Balancing Authority to ensure compliance with BAL-002 may cause the Balancing Authority to be above its high BAAL under BAL-001-2.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Response:

Jamie Lynn Bussin - NaturEner USA, LLC - 5 –

Answer Comment:

I. Introduction

NaturEner USA, LLC and its subsidiaries ("NaturEner") largely support the proposed changes to BAL-002-2, which move the standard towards a performance-based measure of disturbance control response.

While NaturEner largely supports the proposed changes to BAL-002-2, NaturEner believes the standard can be, and should be, even further improved. Specifically, NaturEner recommends that the definition of "Balancing Contingency Event" should be further modified to explicitly include as a qualifying event an unpredicted loss of generation capability. While generator-neutral, the explicit inclusion of this type of event has particular and extreme importance to variable (i.e., renewable) generation, which due to the current inherently imprecise nature of forecasting, unavoidably experience such events at times. The sole reason that NaturEner has abstained in this balloting process, rather than voting affirmative, is because NERC's proposed definition does not explicitly include as a qualifying event an unpredicted loss of generation capability.

NERC's suggested changes to BAL-002-2 propose the following definition of Balancing Contingency Event:

Balancing Contingency Event: *Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.*

	A. Sudden loss of generation: *a. Due to* *i. unit tripping,* *ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or* *iii. sudden unplanned outage of transmission Facility* *b. And, that causes an unexpected change to the responsible entity's ACE;* *B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.* *C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.* NaturEner recommends that the definition should be revised to add a fourth clause to subsection A.a.: iv. *unpredicted loss of generation capability.* Revising that definition as suggested is consistent with the underlying reasons for specifying certain events as Balancing Contingency Events, as NaturEner's suggested revision reflects sudden and unavoidable events affecting the grid, and also supports the efficient and effective deployment of resources and the integration of renewable resources. Moreover on a broader basis, though such a revision to the definition is not required for

reserve sharing groups to include unpredicted loss of generation capability as a qualifying contingency event under which reserve contingencies can be called upon, such a revision to the definition can only help ongoing efforts to encourage reserve sharing groups who have not yet approved such occurrences as qualifying events to do so now.

II. Reasoning

NaturEner collectively is the owner of three wind farms, the Glacier Wind 1 wind farm, the Glacier Wind 2 wind farm, and the Rim Rock wind farm, as well as two wind-based balancing authorities, NaturEner Power Watch, LLC and NaturEner Wind Watch, LLC.

NaturEner takes wind power forecasting extremely seriously, and has invested significant resources to improve our ability to accurately schedule our generation onto the grid. However, there are some weather events that are extremely difficult to forecast and can cause wind generation units to lose generating capability quickly and unexpectedly. These can result from events such as a sudden change in wind direction due to changing weather regimes or localized effects, or from other complex weather interactions which are not well-captured by state of the art forecasting techniques. Though these events are outside of our control and can result in a sudden and large unpredictable loss of generation, such events are currently not recognized as qualifying events in some regional reserve sharing groups.

For conventional generating units in the west, there are few limitations on the cause or frequency of qualifying contingency events. This is consistent with the underlying purpose and rationale of a reserve sharing group - that there are various extreme events which are unpredictable, unavoidable, and can impact reliability. By pooling the resources of participating Balancing

Authorities, reliability can be maintained without requiring individual Balancing Authorities to carry 100% of MSSC in reserves. This is beneficial to the grid, because it avoids costly over-procurement of capacity, while still ensuring the reliability of the system as a whole. The low likelihood that multiple contingencies will occur at the same time means that this shared capacity can be relied upon to be sufficient. Large rapid loss of wind (and solar) events are similarly consistent with the underlying purpose and rationale of a reserve sharing group, in that they there are extreme events which are unpredictable, unavoidable, and can impact reliability. Moreover, if they are appropriately defined and evaluated over a geographically diverse area, they are unlikely to occur at the same time.

The exclusion of extreme loss of wind or solar events from qualifying contingency events leads to at least two negative consequences. First, because the calculation of the resource requirements do not consider regional diversity, the sum of the resource requirements calculated at each individual Balancing Authority-level are much larger than what would be calculated at a system-wide level, leading to systematic over-procurement. Second, due to the increase in capacity resulting from this approach, wind integration tariffs have been implemented in some Balancing Authorities, chilling the ability of new renewable generation to come online in some regions. In contrast, the Midwest ISO has been progressive in implementing market initiatives and programs to enable flexibility in its system and has not needed to increase its reserve capacity as its renewable penetration has increased. The Southwest Power Pool is also a system which has been recognized as a leader in variable integration, and its reserve sharing group makes no limitations on what the cause of a qualifying event is, only that it should be a loss of generation greater than 50 MW. Also with respect to two different weather-related events which result in a loss of generation, members of the Northwest Power Pool (NWPP) are currently allowed to call contingency reserves for high-speed cutouts and for

	temperature extremes. With the conversion of BAL-001 to the BAAL standard, the standard approach of using a "CPS2 Analysis" to determine the reserves required to operate reliably will become obsolete. At this point, the timing issue which NaturEner raised in its January 26, 2015 FERC comments to the proposed rulemaking regarding BAL-001 (FERC 20150126-5252, RM14-10) will become more important (in fact, FERC in its Order in that RM14-10 proceeding, suggested that NaturEner raise the subject matter set forth in these comments in this NERC proceeding (151 FERC ¶ 61,048, at page 26, footnote 72)). In a CPS2 analysis, the monthly ACE is evaluated to ensure that reserves are sufficient such that 90% of the 10 minute periods are within L10, regardless of the magnitude. In a BAAL analysis, the ACE will have to be evaluated such that any single 30 minute period should not exceed the BAAL limits. Due to the timing constraints of 15 minute scheduling and the 30 minute BAAL timer, there will be some ACE events which cannot be resolved by modifying interchange schedules. To ensure that a RBC violation will not occur, BA reserves will need to be carried which can resolve the largest such event which could be observed. This will result in an increase in the inefficient deployment of capacity and related transmission reservations in order to maintain compliance for unpredicted loss of generation capability events unless such events qualify as recognized balancing contingency events. The risk of unnecessary reserve build-outs and holdbacks may be alleviated to some extent if a regional energy imbalance market ("EIM") is implemented, because the market would settle every 5 minutes, thereby resolving the time constraints outlined in our previous comments. However, RBC will come into effect prior to any operational EIM in the WECC. This may in fact result in a system-wide increase in capacity required to be held in reserve and unnecessary reservation of related transmission, and their associated costs.

	Even if and when an EIM is present, however, it still will likely not adequately resolve the problems from unpredicted loss of generation capability unless designed appropriately. It may still cause individual Balancing Authorities to procure more reserve capacity and related transmission than is required to reliably operate the system as a whole. In discussion regarding implementation of an EIM, a resource sufficiency (RS) methodology is being considered by the NWPP to verify that EIM participants enter the scheduling hour with sufficient resources. The work being done in this respect is thoughtful and important. However, the efforts currently being considered also highlight a gap in the existing system in the west. In order to require that participants come to the market “Firm for the hour”, an analysis of the error frequency distribution associated with a Balancing Authority is being done to evaluate error across the next operating hour, using a persistence forecast from 30 minutes prior to the hour. Required reserve capacity will be determined based on a selected probability of events which would exceed that capacity. This work is ongoing, so it is not clear what the final parameters will be, but a probability of 95% has been examined. This analysis will be done on a Balancing Authority level (as opposed to a system-side/reserve sharing group level), and the result of this calculation will be the required reserve capacity needed to allow participation in the EIM. For smaller Balancing Authorities such as ours, this is a catch-22. To integrate our wind with the system, we want (and should want) to participate in the EIM. However, due to the resource sufficiency requirement, the amount of reserves that a Balancing Authority would need to carry would remain unchanged from the current business as usual because the resource sufficiency requirements still assume the scheduling time frames currently in place, and does not allow the benefits of diversity to be included in the assessment of those requirements. For larger Balancing Authorities, this may not seem to be a problem now, because they may currently have sufficient

internal diversity and reserves in their own system to cover the current requirements. However, as load and generation variability continue to increase, thereby requiring capacity reserves to be increased under the considered EIM-related reserve requirements, this inefficiency will also impact those entities, and by extension the cost to the underlying retail consumer.

In order to demonstrate the impact of system-wide aggregation on the reliability of wind generators, the NREL western wind data set [1]from 2006 was used to generate a histogram of the forecast error associated with a regionally diverse subset of the NWPP member states included in that data set. The forecast was assumed to be 30 minute persistence, held constant for the full operating hour. The hysteresis-corrected SCORE value was used to include the impact of both loss of wind and high speed cutouts. A comparison of applying this approach to reserve requirements for both an aggregated 10,000 MW system and an individual 100 MW site are shown in Figure 1 and Figure 2 below. It can be seen that there is much more volatility relative to the installed capacity, which is a result of geographical diversity (i.e., a higher volatility is calculated the smaller the geographic footprint). Further, it can be seen in Figure 2 below that if the proposed resource sufficiency approach was applied at an aggregate system level, and reserve requirements to reach 95% reliability were allocated pro-rata, only 2% of installed capacity would be required. If the individual site level was evaluated to determine the 95% reliability requirements, then the requirements would be 8% or installed capacity, or 4 times what is needed by the system in aggregate. Also note that the NREL data set appears to underestimate the volatility in in the western region, so the actual realized requirements are higher than estimated by that approach.

The impact of calculating a resource sufficiency for an individual site as opposed to an aggregate system is shown in Figure 3 below. On that chart,

the x-axis represents the size of the project being evaluated, and the y-axis represents the resource sufficiency requirements calculated using a 95% probability. It can be seen that as the installed capacity reaches about 1,000 MW, the required reserves on a system wide level drop to 2-3% of installed capacity. In the extreme case where the reserves were calculated at the each individual site level, then the result would be 4 times higher.
Figure 3: Comparison of Reserve Requirement Calculated on Aggregate vs individual statistics

III. Recommendations

NaturEner is extremely appreciative of the work that NERC, WECC, PEAK and the NWPP are doing to improve the efficiency and reliability of the grid. Though the issues that we have raised here may have a greater impact in the near term on smaller Balancing Authorities such ours as compared to larger balancing authorities, as shown above the issues represent a detriment to all grid participants and the consumer, an unnecessary and avoidable hurdle (especially to renewable generation), and an inefficient allocation of capacity reserves and related transmission.

A. Revise the Definition of "Balancing Contingency Event" to Include Unpredicted Loss of Generation Capability.

Accordingly, NaturEner requests that NERC revise the definition of "Balancing Contingency Event" to add a clause iv. to subsection A.a. providing for unpredicted loss of generation capability, so that that subsection will then read as follows:

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System,

iii. sudden unplanned outage of transmission Facility, or

iv. unpredicted loss of generation capability

The SDT believes that the loss of predicted generation *capability* does not impact an entity's ACE. Therefore, the loss of generation capability does not require response in a similar manner to loss of generation. In a loss of renewable generation similar to your example there is no prohibition on the utilization of Contingency Reserve. A change in ACE from the loss of this renewable resource would need to be addressed by an entity experiencing a Reportable Balancing Contingency Event at the same time. As of today, no one has provided a better reserve requirement than MSSC, therefore this is the required reserve recommended in this standard.

B. Other Suggested Recommendations.

In addition to revising the definition of "Balancing Contingency Event" as suggested above, NaturEner suggests that NERC's providing of support and encouragement for the following considerations wherever appropriate would also help both alleviate the problems and advance the benefits discussed above.

1. Efforts should be made to encourage regional reserve sharing groups to allow unpredicted loss of generation capability events as qualifying

	contingency events, to the extent events are not already allowed by such groups. a. Qualifying events could be defined using a reasonable persistence probability of exceedance approach. b. Alternately, the historical contingency events of conventional generators could be evaluated to provide a benchmark for defining the allowable frequency of allowable variable generation contingencies. Unpredicted loss of generation *capability* does not impact ACE therefore, the SDT does not agree with your comment. The definition of a Reportable Balancing Contingency Event takes into account historical events of conventional generator. To the extent renewable generation loss meets the definition of Reportable Balancing Contingency Event the SDT does not believe there is any distinction between renewable generation and conventional generation. To the extent that the comment looks for the SDT to advocate for Reserve Sharing Groups to have specific rules, that is a commercial issue beyond the scope of NERC. 2. Requirements for resource sufficiency in energy imbalance markets should be aligned with specified qualifying contingency events in regional reserve sharing groups. a. Doing so would encourage participation in EIMs, while centralizing the planning for contingency management. 3. Resource sufficiency should be evaluated at a system-wide level, as opposed to at the individual Balancing Authority-level. a. Failure to do this will result in inefficient and unnecessary acquisition and deployment of capacity and related transmission.

	The SDT believes that issues 2 and 3 are commercial in nature and therefore beyond the scope of this drafting team. Devon Yates, Manager, Operational Analytics, NaturEner USA, LLC
Response:	
Jared Shakespeare - Peak Reliability - 1 – **Answer Comment:**	While the SDT has responded to comments on the term “sudden” by saying the word does “not need further definition as any definitive definition would be somewhat arbitrary and possibly ill-fitting for one size entity while perfectly reasonable for another,” Peak continues to believe that lack of a clear definition may cause confusion, disagreement and inconsistency. Absent further clarity in the standard, Peak plans to continue to interpret “sudden loss of generation” as instantaneous or when the breaker trips. The SDT understands that different areas of the North American interconnections handle the definition of “sudden” differently to accommodate the needs of the area. The SDT felt the definition allowed for the specific areas to meet their needs within reason. Peak Reliability’s interpretation works for their needs, however may not work in another area. Therefore the SDT believes that the definition satisfies the entire NERC body. The language in R1.1 is confusing with respect to the expectations for multiple Balancing Contingency Events. Please provide an example of the required recovery magnitude and timeline of multiple Balancing Contingency Events.

The SDT believes that an entity can utilize CR Form 1 to run different scenarios, thus providing an entity with examples of the required recovery magnitudes and timelines for multiple Balancing Contingency Events.

Please provide a technical justification for the varying thresholds in the different Interconnections. It is unclear why the threshold in the Western Interconnection would be vastly lower than the threshold in ERCOT or even than the Eastern Interconnection. For example, there are 50 units with a PMAX of 500 MW or greater in the Peak RC Area. This is a significant number that will lead to more DCS events that do not significantly impact reliability but will distract from other key monitoring activities.

The MW thresholds are based on a statistical evaluation of historical events in each interconnection and their impact on frequency in that interconnection. At a high level, the definition of a frequency event in each interconnection is defined by the frequency impact of an event and the interconnection characteristics. Please refer to the Background Document posted with this standard. The SDT utilized conservative numbers in order to provide the System Operators with the necessary information to operate the grid while maintaining compliance.

Response:

Additional Comments Received from Steve Johnson – Western Area Power Administration

Thank you for the opportunity to comment on the draft BAL-002-2 standard. Western Area Power Administration would like to provide the following comments:

1. We request clarification on the “system models” information.

System models are those models that are used to plan reliable operation of the interconnection. The models would be used for near-term (next hour to next week) planning as well as longer term planning. Whether this is a single model used by an entity or multiple models used by an entity, each of them would be expected to include an evaluation of the entity's likely contingencies as required under the TPL standards.

2. We would like to request clarification on the clock-hour language that was included in the R2 rationale, but removed. The focus here is that we want to make sure the clock-hour average is still how we will be measured and not individual AGC cycle contingency reserves calculations for carrying sufficient reserves.

   Under the proposed standard, there is no real-time measurement of Contingency Reserves in R2. Instead, the requirement is for the day-ahead Operating Plan to show that there is an expectation that the Responsible Entity will have the necessary Contingency Reserves. The time frame for this plan is dependent upon the time frame used by the Responsible Entity.

3. In 1.3 its stated "deploy Contingency Reserve, within system constraints." We are not sure what is meant by "system constraints" please clarify.

   The normal constraints that are used for determining the limits of the system, including System Operating Limits, Interconnection Reliability Operating Limits and other pertinent operating limits determined by the Transmission Operator, Generator Operator, Balancing Authorities and monitored by the Reliability Coordinator(s).

Additional Comments Received from Phil Hart – Associated Electric Cooperative, Inc.

AECI appreciates the drafting team's persistent efforts to further improve BAL-002-2 through standards development. The requirements within the current revision are an improvement over the currently enforceable BAL-002-1 and previous revisions. However, after considering FERC's approval of the BAAL operating criteria (BAL-001-2 R2) in Order 810, the reliability benefit, or need, of a BAL-002 standard is no longer apparent.

The objective of the BAL-002 standard could arguably be redundant with the contingency reserves inherently required to be compliant with the BAAL operating criteria. The objective of BAL-002-2 states: "... to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event." Without proper context this objective sounds very similar to the understood objective of the BAAL operating criteria, with two distinct differences: BAL-002-2 requires an ACE value return to be performed without any consideration for interconnection health (frequency), and this recovery is required to be 15 minutes instead of 30 (which the 10 year field trial found to be a reliable time period for recovery). These differences do not mitigate any additional risks to the system, rather they create additional risks to the system.

By imposing additional requirements above and beyond BAL-001-2, the BAL-002 standard can negatively affect reliability by forcing entities to disregard the frequency of the interconnection and respond with corrective action that would push interconnection frequency further from schedule. Standards requirements should not require "backup" standards requirements, these requirements mandate to entities "how" they must comply with another standard and only create regulatory burden for entities.

Compliance with BAL-001-2 R2 inherently requires a contingency reserve policy, and will be required continent wide. The unexpected loss of generation or load is an assumed risk that is taken by Balancing Authorities while striving to meet customers energy demands. They also assume compliance risks. If an entity does not carry sufficient reserves or has measures in place to import energy (RSG, interchange transactions, etc) prior to an event occurring, AND their lack of response in a timely fashion creates a negative impact to the Bulk Electric System, they will be in violation of the BAL-001-2 standard. To mitigate this compliance risk, entities MUST carry contingency reserves. If they do not then they will eventually violate BAL-001-2 R2. If they do not violate BAL-001-2, then no real risk to reliability was imposed on the system and any requirement that determined a non-reliability related event as a violation would prove itself to be non-risk based.

The BAL-002 project has been a long one. While the project intent and associated FERC directives may have been applicable during the initial phases of development, the recent acceptance of the BAL-001-2 and BAL-003-1 standards could warrant the development of an alternate approach. For instance, a specific definition of the remaining directives and their relationships to BAL-001 and BAL-003 could prove that these directives have been met. A refocus of the team's effort now, as opposed to later, may be a better use of NERC and industry resources while also advancing the NERC initiative for Results Based Reliability Standards Development. For this reason, AECI requests that NERC and the drafting team re-evaluate the reliability risks related to this standard, along with the outstanding FERC directives, to evaluate the need for the BAL-002 standard.

Until BAL-001-2 has been fully implemented, data has been collected and evaluated, it would be difficult to show the reliability impacts of a complete retirement of BAL-002-1. Further, the team has determined that there is a reliability gap absent BAL-002-2. Also, through the standard development process for this project, numerous issues with the current standard have been identified. As such, the proposed standard provides clarity for the issues that have been identified to date.

Additional Comments Received from the ISO Standards Review Committee

The SRC agrees with the intention of the SDT draft 7 posting to:

- Provide the risk based parameters (ACE range, Recovery period, Restoration period) for responding to a Balancing Contingency Event (BCE);
- Ensure that the definition of Most Severe Single Contingency (MSSC) does not include more than one resource;
- Ensure that the definition of BCE does recognize the possibility of the loss of more than one resource;
- Eliminate draft 6's hourly obligations; and
- Clarify that shedding load is not an expected action in order to maintain reserves.

The SRC does not agree with proposed standard wording that:

- Links MSSC to BCE; and
- Links Contingency Reserves (CR) to Disturbance Control Standard (DCS) compliance.

The SRC proposes clarifying modifications to definitions for:

- Balancing Contingency Events;
- MSSC;
- Contingency Event Recovery Period; and
- The EEA level referenced in R1.3.1

The SRC again asks the SDT to remove the language within draft 7's proposed CR requirement that ties DCS compliance to the use of CR.

For compliance with Requirement R1 Part 1.1 response is determined by your ACE within the first 15 minutes regardless of how recovery is accomplished. Requirement R1 Part 1.3 describes the process for when events combine to be greater than MSSC and provides exclusion from compliance for Part 1.1. However, exclusion from compliance for Part 1.1 does not allow an entity to avoid responding at all to a large event. Note that Part 1.3 does not require all Contingency Reserves be activated.

The SRC has characterized its comments in three classifications: those proposed to facilitate clarity; those proposed to ensure that the focus of requirements remains on reliability; and those proposed to address other concerns.

Revisions Proposed To Facilitate Clarity

The SRC would ask that the SDT to redraft the requirements in more direct terms. Phrases like "demonstrate recovery" in the requirement section of the standard can be construed ambiguously and a clear reliability requirement omits unnecessary words and directly defines the obligation.

In particular, the SRC suggests that the linkage between R 1.1 and R1.31 is a source of ambiguity within the standard because:

- Requirement R1.1 defines the target ACE correction (range of recovery);
- Requirement R1.3 defines Contingency Reserve deployment;
- Sub-Requirements of R 1.3 then introduce exceptions for **R1.1** (*i.e.*, R 1.3.1 and R 1.3.2).

This organization does not allow readers and entities responsible for compliance and direct correlation between specific defined obligations and the proposed exemptions. To facilitate clarity, the SRC offers two recommendations. The first recommendation preserves much of the current, draft language while the second recommendation provides more streamlined language:

1. *Retaining current draft language:*

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

~~**1.2.** document all Reportable Balancing Contingency Events using CR Form 1.~~

~~**1.3.** deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if: **1.3.1** the Responsible Entity is:~~

Unless:

- the responsible entity:
  - is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher; is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan; or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency .

~~or,~~

- the following subsequent event(s) occur:

~~**1.3.2** the Responsible Entity experiences:~~

  - multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Even;, or
  - multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

2. *More direct version*:

R1. Unless the Responsible Entity is experiencing any Reliability Coordinator-declared Energy Emergency Alert Level 1 or higher, is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, , the Responsible Entity experiencing a *Reportable Balancing Contingency Event* (RBCE) shall return its ACE to:

- Zero within the *Contingency Event Recovery Period* if the Responsible Entity's Pre-RBCE ACE Value were positive or equal to zero; or
- Its Pre-RBCE ACE Value if the Responsible Entity's Pre-RBCE ACE Value were negative

Where a Balancing Contingency Event exceeds the responsible entity's MSSC or multiple Balancing Contingency Events occur within the Contingency Event *Restoration period* of the 1st RBCE, the responsible entity shall deploy contingency reserves, but such response shall not be subject to Requirement R1:

The drafting team appreciates the commenters effort to make the language clearer. The SDT believes that the existing format provides the clarity needed withal details. The proposed eliminations and reformatting does not accomplish the SDT's intent. The proposed EEA level is unsupportable. According to the definitions of the EEA levels, there is no acceptable reason to excuse performance for an entity in an EEA Level 1. According to the definition of the EEA Level 1, an entity should have all necessary contingency reserves. Therefore the entity should respond according to R1 and correct their ACE within the Disturbance Recovery Period.

Revisions proposed to ensure that the focus of requirements remains on reliability

The SRC asserts that the primary focus of BAL-002 should be reliability (ACE recovery) with less focus be given to the specific process regarding how to meet the reliability requirement. The current draft appears to link economic sharing arrangements (Contingency Reserves) to a reliability requirement and, therefore, precludes the use of more effective processes to meet the reliability requirement. The SRC cautions the SDT against mandating the use of a process where such usage would be inappropriate from both a reliability and cost efficiency perspective when other processes are available For example, as written, draft 7 could preclude the use of Demand Side Management (DSM) as Contingency Reserves (in contradiction of Order 1000), and restricting DSM to Emergencies only. For these reasons, the requirements should be re-focused on what needs to occur for reliability – not how such activities are performed.

The drafting team's main focus is on reliability and as drafted, states the requirement but does not define how an entity must accomplish the goal. For example, the requirements do not require the use of Contingency Reserve for a measured Reportable Contingency Reserve Event. The measurement is only based on the ACE value within 15 minutes from the time of the event. The only area where there is a required use of Contingency Reserves is for events that exceed an entity's Most Severe Single Contingency. In these cases, there should not be an expectation that a system operator need do nothing since the event is not going to be subject to mandatory compliance. Instead, the expectation should be that the operator will address the imbalance created *to a reasonable extent through the use of deliverable Contingency Reserves* without a requirement to fully restore ACE to any specific level.

The SRC does recognize the SDT's attempt to address the issue of maintaining reserves designed to preserve serving load verses the issue of shedding load to preserve reserves and that it makes no sense to shed load to maintain reserves that are designed to protect load from being shed.   Additionally, the SRC questions the need for the proposed Requirement R2 (*i.e.*, the requirement to have a method to compute MSSC).

Such requirement is administrative in nature as it mandates a creation of a procedure, an implementation process for that procedure, as well as a mandate to "have" a market service to calculate MSSC. The sentence in draft 7 can be read as ether:

- an annual obligation to compute MSSC and to use that annually-computed MSSC in system operations, and
- carry an equivalent amount of reserves for that year

or

- develop a plan to explain how to compute MSSC and review that plan every year
- implement the computation (the implication is that the plan will introduce the time frame for updating MSSC)
- carry an equivalent amount of RC (for as long as the plan states)

The definition of MSSC is axiomatic and does not require a formal procedure. The only plausible justification for having such a plan is mandate self-imposed rules regarding when to compute MSSC; how to apply that calculation; and for how long. Given the ambiguity in draft 7's R2, either approach can be justified. Such ambiguity would not serve reliability. As an example, if draft 7 really did intend linking MSSC to an annual value, and in doing so lock-in a minimum reporting value (80% of MSSC), then what could occur is that small BAs can have a minimum reportable value that is larger than any unit that is operating on a given day – in effect - exempting them from ever reporting. On the other hand, if draft 7 really did intend to provide flexibility to the BAs, a number of questions arise: Is this a daily scheduling function, or a continuous operating function? Is the objective fixed or does it depend on what is operating at the given time? Accordingly, the current approach could be interpreted broadly and variably and should be revised as it does not appear to be directly focused on or facilitating reliability.

The drafting team believes that the Operating Process developed by the Responsible Entity would address these concerns related to potential ambiguity. The drafting team understands that it is possible, although somewhat unlikely for an entity to have an MSSC that does not change during the course of an operating year for several reasons. However, the drafting team does not believe that this is an issue in the standard. Rather it is an issue that entities need to address as part of the required Operating Process. As an example, an entity may determine that the largest loss it could ever expect would be 1,000 MW so that is the level they will carry at all times, regardless of their real-time number being lower on any given day. This would be a means to ensure that compliance with R1 would not be an issue, although arguably it may not be very efficient. Another entity could decide that the loading of a transmission line far exceeds the size of the largest generator so they would plan to forecast the line loading and set a floor for their Contingency Reserves equal to the size of their largest generator, thus allowing the MSSC to fluctuate each hour in their Operating Plan. However, in both cases, the real-time number will drive compliance with R1. Therefore, the drafting team believes that the proposed definitions and requirements address appropriately the possible operational practices.

Revisions Proposed to Address Other Concerns

The SRC suggests the following comments and/or revisions for the SDT's consideration:

1. Delete the phrase "within system constraints" in Requirement R1. Because BAs are not responsible for system constraints (that's the role of TOP), the inclusion of this phrase connotes that a BA can be held responsible for exacerbating a SOL problem, even if the BA had no knowledge of the limit and was taking actions to comply with its obligations. The requirements should respect current roles and responsibilities of the various functions and, currently, the TOP is responsible for directing the BA in this regard.

The drafting team agrees the BA is not responsible for determination of system constraints. However, the following selected list of Requirements from Standards, either currently enforceable or approved by the NERC Ballot Body, NERC Board of Trustees and filed at FERC requesting approval for future enforcement, makes it clear that a Balancing Authority can't perform their duties reliably without being knowledgeable of system constraints.

TOP-001-3 R20
TOP-002-2.1b R4, R5, R6, R7, R9 and R10
TOP-002-4 R4
TOP-003-1 R1.2
TOP-003-3 R2, R4 and R5

Finally, removing the phrase would make a requirement to activate all Contingency Reserves, regardless of any negative impacts to the Bulk Electric System for large events. The drafting team discussed this concern and determined that the BA should only activate the level of reserves that could be safely used without creating reliability issues on the grid.

2. The standard has a reporting requirement, but does not include a reporting timeframe. Therefore, the most conservative assumption would be that reporting is on and "individual event" basis. For draft 7, the SDT rejected quarterly reporting based on a non-relevant paragraph in Order 693.

> 354. First, the Commission directs the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard. This is consistent with our position in the NOPR and NERC's position in response to the Staff Preliminary Assessment of the Requirements in BAL-002-0, and was not disputed or commented upon by any NOPR commenters.

The SRC requests that the SDT explain its correlation between the reporting requirement and P 354 and requests that the SDT clarify the timing of any required reporting. Additionally, the SRC is unclear as to how "the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure." Upon review, it appears that values for entities are calculated on a % of recovery whether applied to an individual event or quarterly performance – accordingly the severity of a violation would still be correlated to overall performance for some time period. The SRC requests that the SDT re-evaluate its explanation and provide additional clarification.

R1 part 1.2 does not require a report to be submitted to any entity, only to "document all Reportable Balancing Contingency Events" in a manner that ensures consistency. It requires the documentation of an entity's restoration of ACE be on the referenced form to demonstrate that the entity did restore its ACE as required. This ensures all entities utilize the same methodology for each event. Refer to the measurement for R1 to see that the form is used to calculate the response, not to report anything to NERC or a Regional Entity. The drafting team did not put a requirement into the standard that an entity report a failure as this is a compliance issue and should not be part of a reliability standard.

3. The Draft 7 definitions of MSSC and BCE do not resolve the issue of BCE being greater than the MSSC because Draft 7 continues to link the definitions of MSSC and BCE. The SRC believes MSSC is an a priori / actual state value while BCE is an a posteriori event/experience. The SRC agrees with the SDT that MSSC can never be more than one resource otherwise it would not be a "single contingency." BCE on the other hand can (as the current definition indicates) include the impacts of the loss of more than one resource. To address this concern, the SRC offers the following comments and revisions.

    Draft 7 definition of MSSC:

    Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency as identified and maintained in the system models within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a

Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Draft 7 definition of Event:

Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:

a. Due to

i. unit tripping,

ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or

iii. sudden unplanned outage of transmission Facility;

b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Given the above definitions, the SRC concludes that the SDT correctly wants to ensure that MSSC include large interchange schedule imports as well as large generators. The definition of BCE does that (see sub item B). The draft 7 definition of MSSC relies on the definition of BCE to ensure that such interchange gets considered. The problem is that the foreword of the BCE definition includes the phrase "or any series of such otherwise single events." That addition makes it virtually impossible to quantify / limit one single resource amount for an MSSC.

The SRC would suggest that Draft 7 definition of Event be retained, but that the definition of MSSC be redrafted. The SRC suggests:

> MSSC is the MW capacity of the single largest resource scheduled to operate for a given day's peak load. The resource may be a generator (Maximum Continuous Operating Capacity) or a Firm Interchange scheduled import.

This revision:

- Changes the MSSC definition from being linked to a Balancing Contingency Event of undefined size, to linking MSSC to an easily identified single resource capacity/expectation.
- Can be used to provide clarity concerning why and how the amount of CR can be set to a daily MSSC; and how and why every CBE can be "reported" upon without being subject to the DCS objectives for an MSSC.

The definition of MSSC states "due to a single contingency" and identified in the system models. The phrase "any series of such otherwise single events" is utilized for recovery measurement, not establishment of Most Severe Single Contingency. However, in actual operation, there can be events that are nearly simultaneous. In order to clarify that these events could be considered a single Balancing Contingency Event, the definition of Balancing Contingency Event provides for this. However, the Reportable Balancing Contingency Events are limited to the size of the identified MSSC.

The Draft 7 definition CR does not define what CR is, but rather defines what CR may be used for. Moreover, the definition's use of the phrase "provision of capacity" requires further explanation to clearly delineate between the concept of "provision of capacity" in the Operating Planning environment (meaning to request that resource be made available to serve load) versus the "provision of capacity" in the compliance/operating environment (meaning the amount of energy that was produced at the request of the BA). An additional issue with the first sentence is that, as written, it specifically excludes the use of those reserves to serve firm customer load. To address this concern, the SRC offers the following comments and revisions.

> Draft 7 definition of Contingency Reserves

Draft 7 definition of Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

The SRC suggests that the issue of CR and reserves in general requires an Industry-wide review; and the SDT in its introduction to its Response to Comments propose the ERO conduct such a review prior to making a decision on a final ballot. The review would be used to decide if:

- Reserves were linked to day ahead scheduling in the sense that "reserve" capacity over and above the capacity scheduled to meet a peak load. This concept was referenced in the original Policy 1 – Generation Control and Performance, (dated Feb 1, 1997) at romanette (i) If CR were viewed as scheduled available system capacity there would be no issue, because then the measurement of reserves would be focused on the planned capacity for the day. Once that capacity is synchronized it can be used for any and all purposes.

To the extent that this comment is looking for clarity of all types of reserves and how they interact, please refer to NERC's Reliability Guideline: *Operating Reserve Management*, available on NERC's website under the Operating Committee "Reliability Guidelines" link listed under the Committee Resources. The document was originally developed by the drafting team and approved by the NERC Operating Committee in 2013. A link to this page is provided below.

http://www.nerc.com/comm/OC/Pages/Reliability-Guidelines.aspx

The drafting team believes that the definition of Contingency Reserves is clear as proposed.

Supporting Diagrams Submitted by Jamie Lynn Bussin – NaturEner

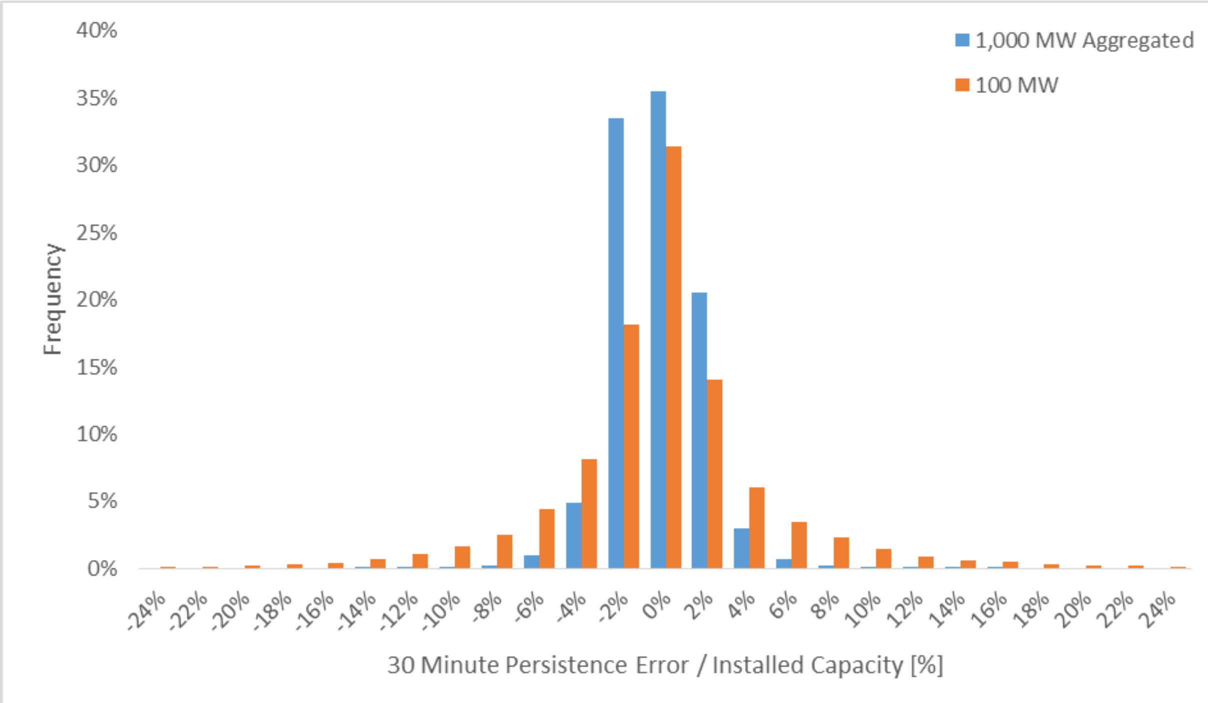

Figure 1: Histogram Comparing 30 minute ahead Persistence Forecast Error Distribution from NREL data set

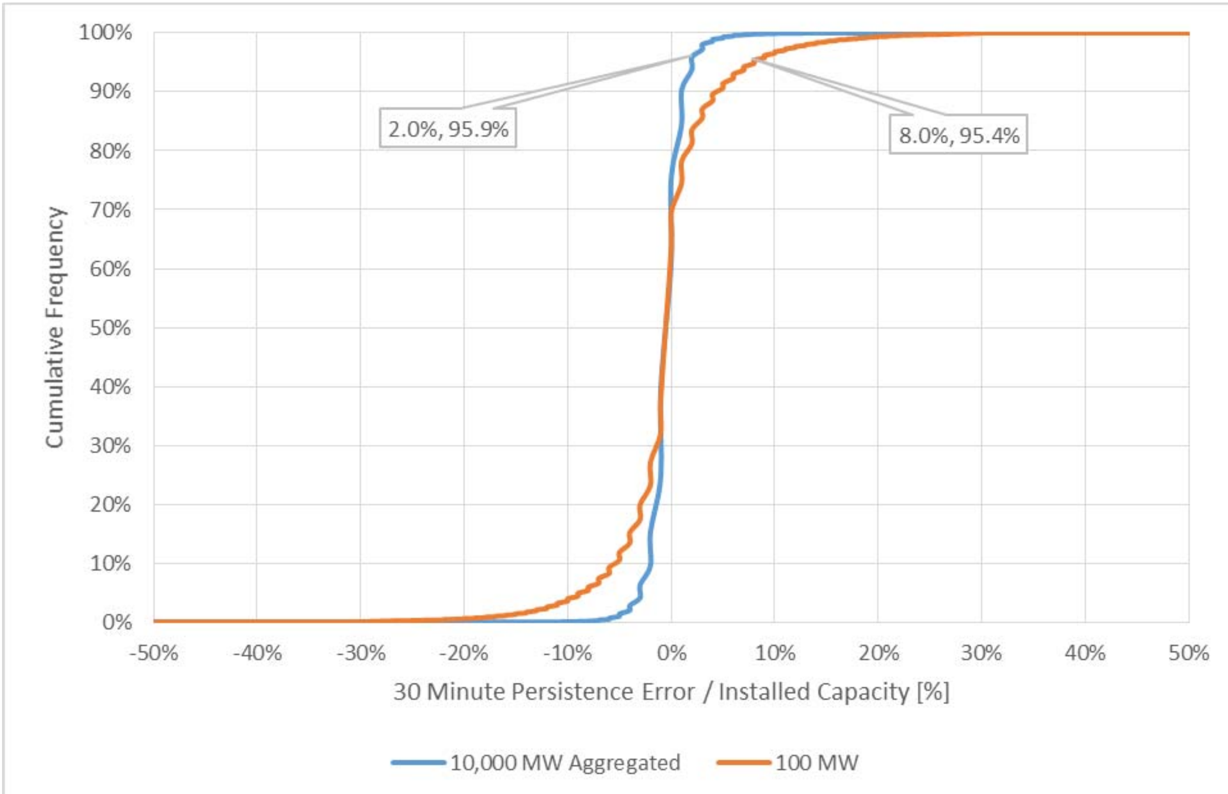

Figure 2: Cumulative Histogram Comparing 30 minute ahead Persistence Forecast Error Distribution from NREL data set

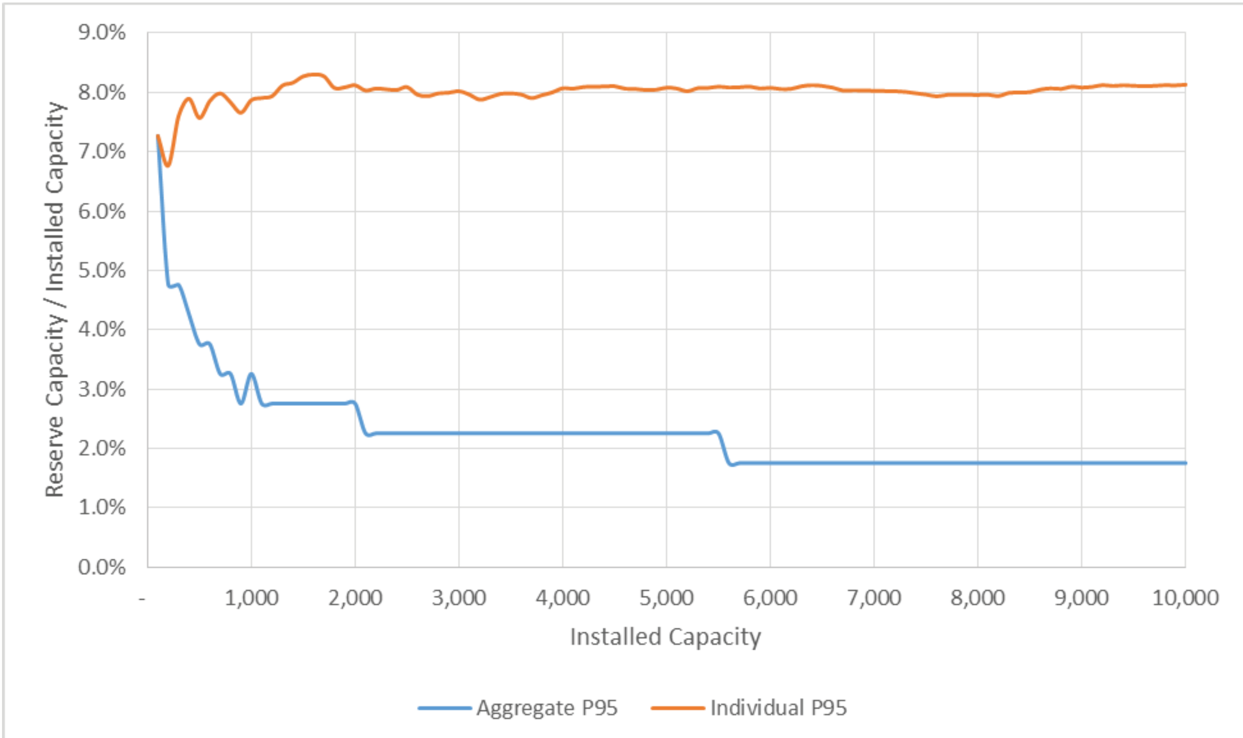

Figure 3: Comparison of Reserve Requirement Calculated on Aggregate vs individual statistics

End of Report

Standard Development Timeline

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

Description of Current Draft

(Describe the type of action associated with this posting, such as 30-day informal comment period, 45-day formal comment period with parallel ballot, 45-day formal comment period with parallel additional ballot, final ballot.)

Completed Actions	Date
The SAR for Project 2007-18, Reliability Based Controls, was posted for a 30-day formal industry comment period.	May 15, 2007
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The sixth draft standard was posted for a 45-day formal industry comment period and additional ballot.	January 29, 2015
The seventh draft standard was posted for a 45-day formal industry comment period and additional ballot.	July 7, 2015

Anticipated Actions	Date
Final ballot	September 2015
NERC Board adoption	November 2015

New or Modified Terms Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit tripping,
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG), or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW

- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Rationale for Contingency Reserve Definition: Originally a waiver of the R3 Contingency Reserve Restoration requirement was proposed in the event of an Energy Emergency Alert (EEA). This was predicated on a definition of Contingency Reserve that did not include readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA and on concern that the attempt to restore Contingency Reserve during an EEA could result in actual curtailment of Firm Demand in order to free up generation not to be used but merely to be counted as restored Contingency Reserve when no other Balancing Contingency Event arose. As an alternative to waiving R3, and to remedy the concern, readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA was proposed for inclusion in the definition of Contingency Reserve as it would make Firm Demand merely ready to be curtailed in case another Contingency arose during an EEA.

Readiness to reduce Firm Demand here is a way of providing Contingency Reserves exclusively when the Responsible Entity is in a Contingency Reserve Restoration Period during an emergency. Readiness means the Responsible Entity is prepared to reduce Firm Demand to mitigate events which may increase demand or reduce supply causing unacceptable risk. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event.

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-2.
6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language in Requirement 1 Part 1.3.1 such that it addresses both current and future EEA process. In addition, the drafting team has added some clarifying language to 1.3.1 since comments were presented in previous postings expressing a concern only a Balancing Authority may request declaration of an EEA and a RSG cannot request an EEA. The standard drafting team's intent has always been if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or

- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

Rationale for Requirement R2: R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity’s Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

Rationale for Requirement R3: This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Real-time Operations**	**Medium**	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	**Operations Planning**	**Medium**	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the

			greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain annually the Operating Process.		Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	Responsible Entity's Most Severe Single Contingency..
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	Commission approved BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
2	November 2015	NERC Board Adoption	Complete revision

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

Rationale

Upon Board approval, the text from the rationale boxes will be moved to this section.

Standard Development Timeline

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Anticipated Actions	Date
~~45-day formal comment period with parallel additional ballot~~	~~June/July 2015~~
Final ballot	~~July~~ September 2015
NERC Board adoption	~~August~~ November 2015

New or Modified Terms Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard.

Term:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to
      i. unit tripping,
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility;
   b. And, that causes an unexpected change to the responsible entity's ACE;
B. Sudden loss of an import, due to unplanned outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency ~~as~~ identified ~~and maintained in the~~using system models maintained within the Reserve Sharing Group (RSG), or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection - 900 MW
- Western Interconnection – 500 MW

- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Rationale for Contingency Reserve Definition: Originally a waiver of the R3 Contingency Reserve Restoration requirement was proposed in the event of an Energy Emergency Alert (EEA). This was predicated on a definition of Contingency Reserve that did not include readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA and on concern that the attempt to restore Contingency Reserve during an EEA could ~~well~~ result in actual curtailment of Firm Demand in order to free up generation not to be used but merely to be counted as restored Contingency Reserve when no other Balancing Contingency Event arose. As an alternative to waiving R3, and to remedy the concern, readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an EEA was proposed for inclusion in the definition of Contingency Reserve as it would make Firm Demand merely ready to be curtailed in case another Contingency arose during an EEA.

Readiness to reduce Firm Demand here is a way of providing Contingency Reserves exclusively when the Responsible Entity is in a Contingency Reserve Restoration Period during an emergency. Readiness means the Responsible Entity is prepared to reduce Firm Demand to mitigate events which may increase demand or reduce supply causing unacceptable risk. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event.

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-2
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-2.
6. **Background:**

   Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

B. Requirements and Measures

Rationale for Requirement R1: Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language in Requirement 1 Part 1.3.1 such that it addresses both current and future EEA process. In addition, the drafting team has added some clarifying language to 1.3.1 since comments were presented in previous postings expressing a concern only a Balancing Authority may request declaration of an EEA and a RSG cannot request an EEA. The standard drafting team's intent has always been if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3.1 the Responsible Entity ~~is~~:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- ~~the Responsible Entity~~ has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or

- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

Rationale for Requirement R2: R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity’s Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

Rationale for Requirement R3: This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration ~~p~~Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

C. 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. Evidence Retention

The following evidence retention period(s) 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.

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:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	Operations Planning	Medium	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the

			greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain annually the Operating Process.		Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	Responsible Entity's Most Severe Single Contingency..
R3	**Real-time Operations**	**Medium**	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document

CR Form 1

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	Commission approved BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
2	November 2015	NERC ~~BOT~~ Board Adoption	Complete revision

Standards Attachments

NOTE: Use this section for attachments or other documents that are referenced in the standard as part of the requirements. These should appear after the end of the standard template and before the Supplemental Material. If there are none, delete this section.

[Application Guidelines, Guidelines and Technical Basis, Training Material, Reference Material and/or other Supplemental Material]

Rationale

Upon Board approval, the text from the rationale boxes will be moved to this section.

Implementation Plan

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

BAL-002-2

Approvals Required

BAL-002-2 – Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

- A. Sudden loss of generation:
  - a. Due to
    - i. unit tripping, or
    - ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
    - iii. sudden unplanned outage of transmission Facility;
  - b. And, that causes an unexpected change to the responsible entity's ACE;
- B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
- C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

Applicable Entities

Balancing Authority[1]

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

[1] A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. *See* Section A.4.1.1.1, BAL-002-2.

Reliability Standard BAL-002-1, Disturbance Control Performance shall be retired immediately prior to the effective date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

The existing definition of Contingency Reserve should be retired immediately prior to the effective date of BAL-002-2, in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan

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

BAL-002-2

Approvals Required

BAL-002-2 – Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event

Prerequisite Approvals

None

Revisions to Glossary Terms

The following definitions shall become effective when BAL-002-2 becomes effective:

Balancing Contingency Event: Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
    a. Due to
        i. unit tripping, or
        ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
        iii. sudden unplanned outage of transmission Facility;
    b. And, that causes an unexpected change to the responsible entity's ACE;

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency ~~as~~ identified ~~and maintained in the~~using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part ~~of a Res area that is not part~~ of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Reportable Balancing Contingency Event: Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity.

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Pre-Reporting Contingency Event ACE Value: The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.

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

Contingency Reserve: The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

~~The existing definition of Contingency Reserve should be retired at midnight of the day immediately prior to the effective date of BAL-002-2, in the jurisdiction in which the new standard is becoming effective.~~

Applicable Entities

Balancing Authority[1]

Reserve Sharing Group

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

BAL-002-2 shall become effective the first day of the first calendar quarter that is six months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Justification

The six-month period for implementation of BAL-002-2 will provide ample time for Balancing Authorities to make necessary modifications to existing software programs to ensure compliance.

Retirements

[1] A Balancing Authority that is a member of a 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 governing rules for the Reserve Sharing Group. *See* Section A.4.1.1.1, BAL-002-2.

Reliability Standard ~~BAL-002-0, Disturbance Control Performance, and~~ BAL-002-1, Disturbance Control Performance shall be retired ~~at midnight of the day~~ immediately prior to the ~~E~~effective ~~D~~date of BAL-002-2 in the particular jurisdiction in which the new standard is becoming effective.

The existing definition of Contingency Reserve should be retired immediately prior to the effective date of BAL-002-2, in the particular jurisdiction in which the new standard is becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

BAL-002-2
Background Document

September 2015

RELIABILITY | ACCOUNTABILITY

Table of Contents

Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple a methodology to adequately address all of these interactions. The suite of NERC Standards work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002),

this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert.

For additional technical justification for exemption from R1 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance.

In addition, the standard drafting team (SDT) through R1 Part 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the

number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

- If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

• Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:

- If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
- If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
- If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

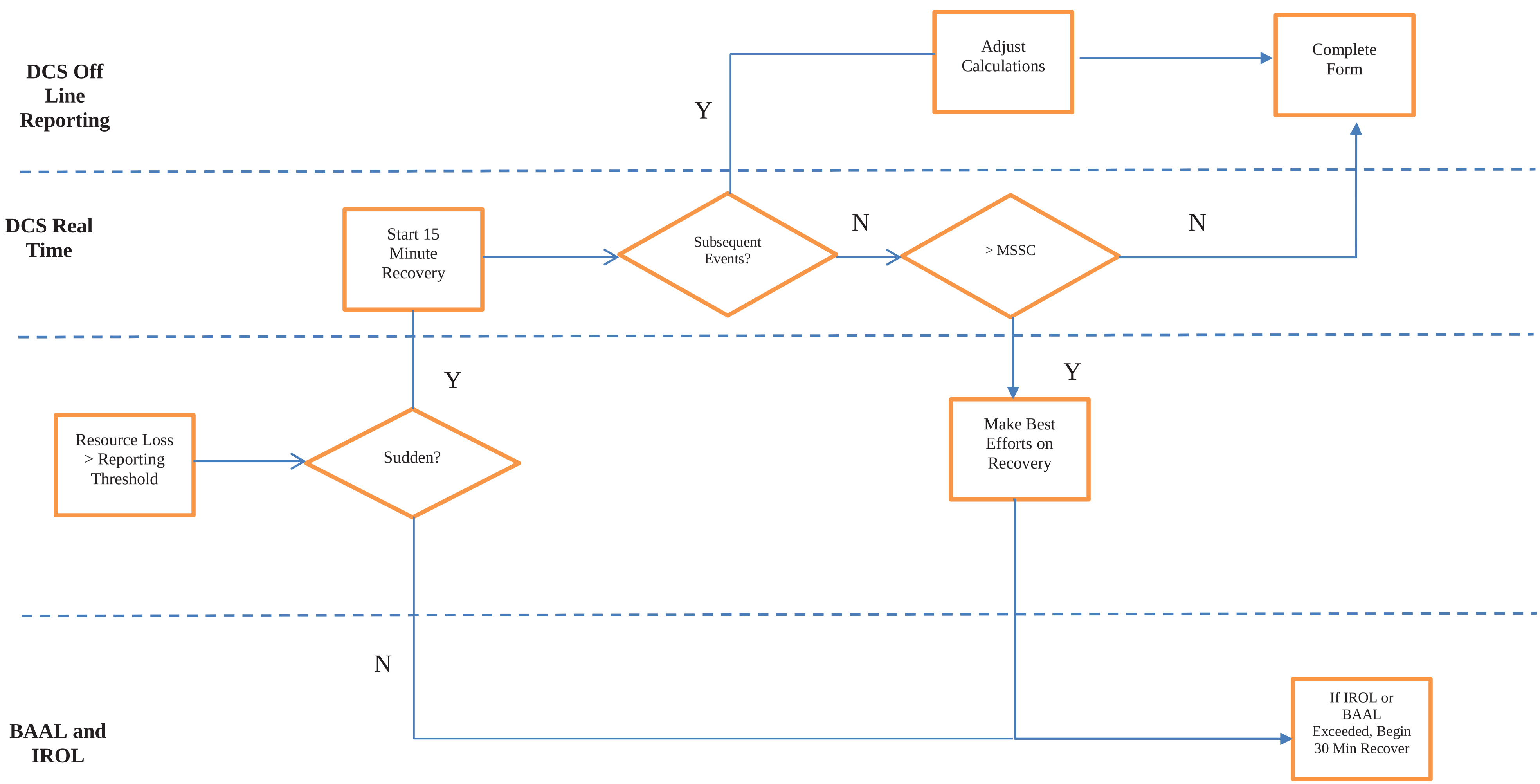
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve be at least equal to the applicable entity's Most Severe Single Contingency and a definition of Most Severe Single Contingency. Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, Requirement R3 addresses restoration of the reserves.

Requirement 3

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events. This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes.

Attachment 1

NERC Interconnections 2009-2013

Frequency Events Loss MW Statistics

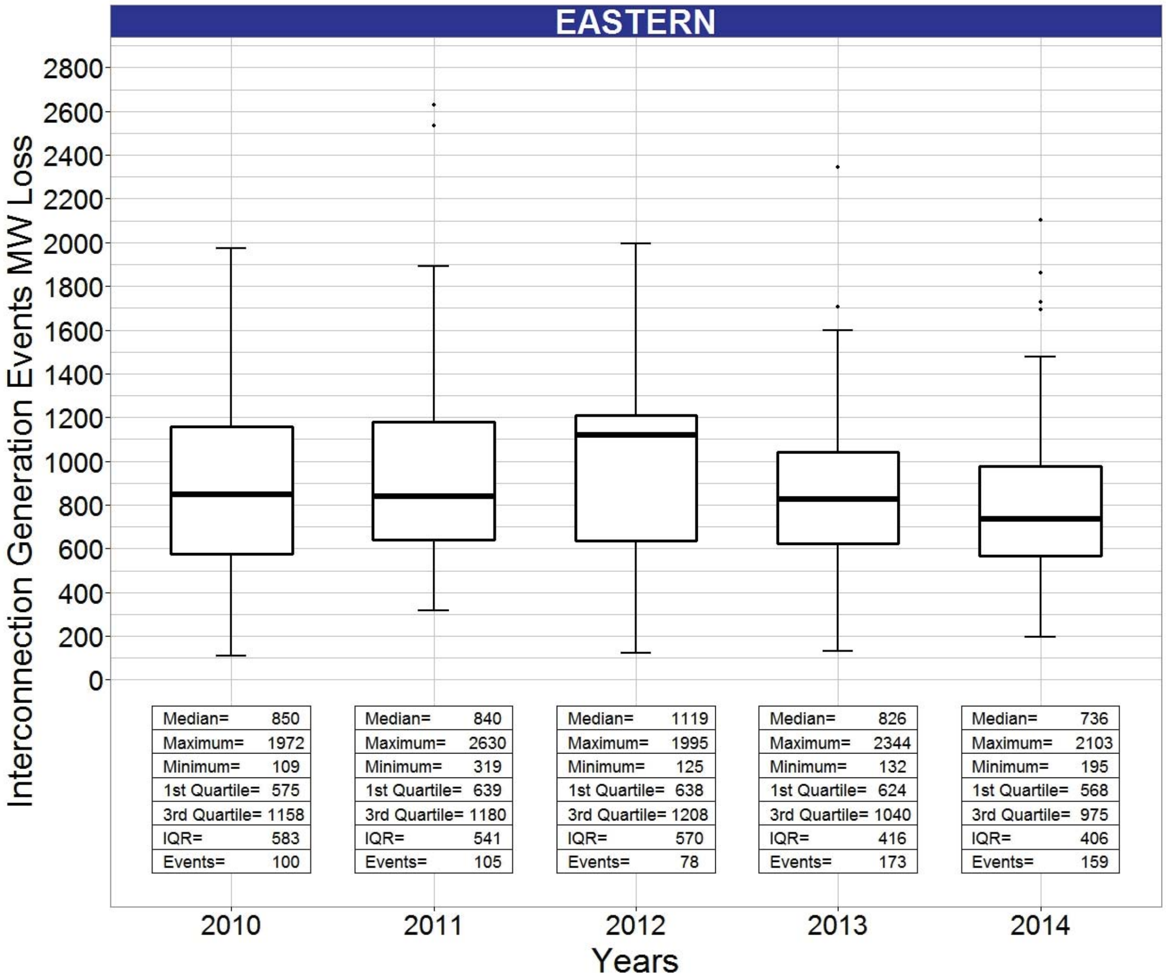
For: NERC BARC Standard Drafting Team

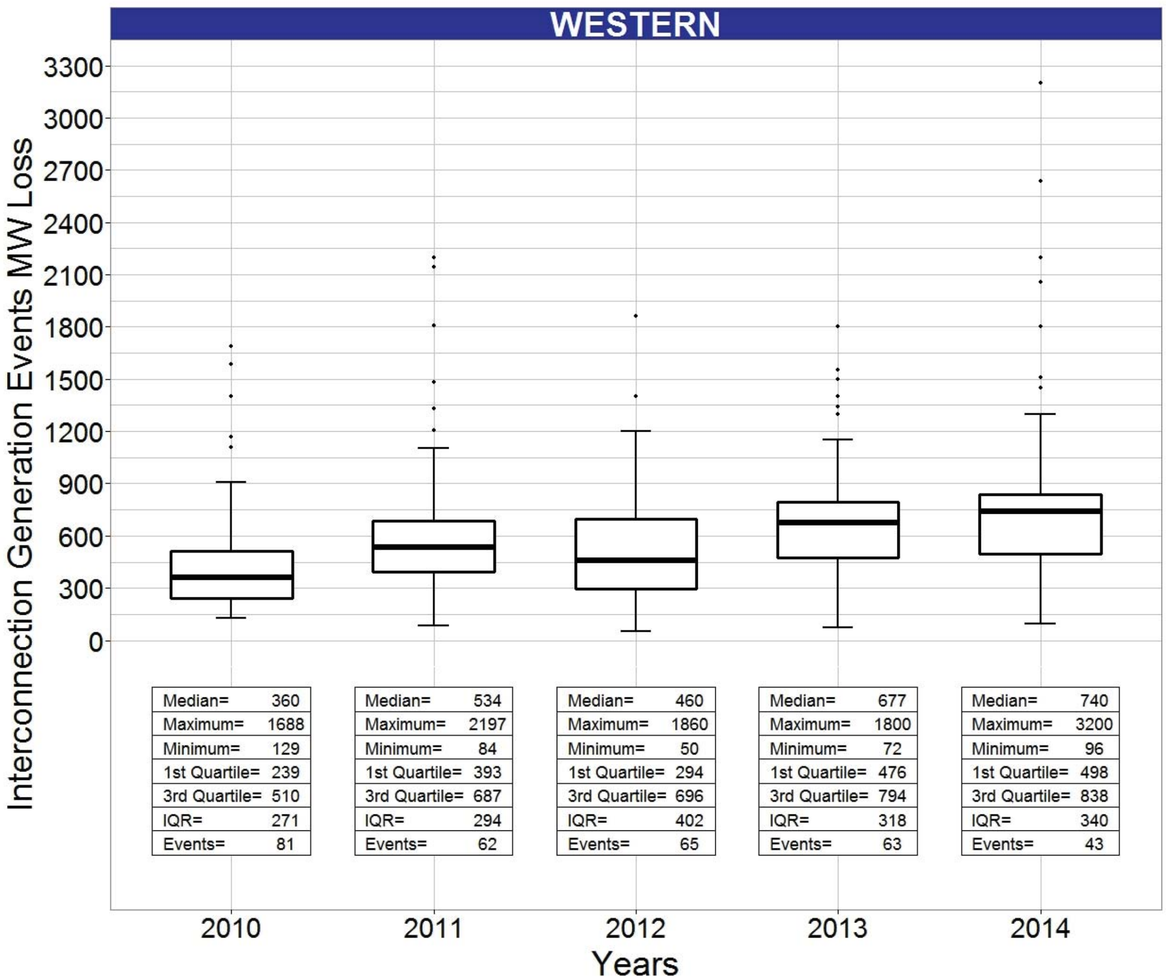
Prepared by: CERTS

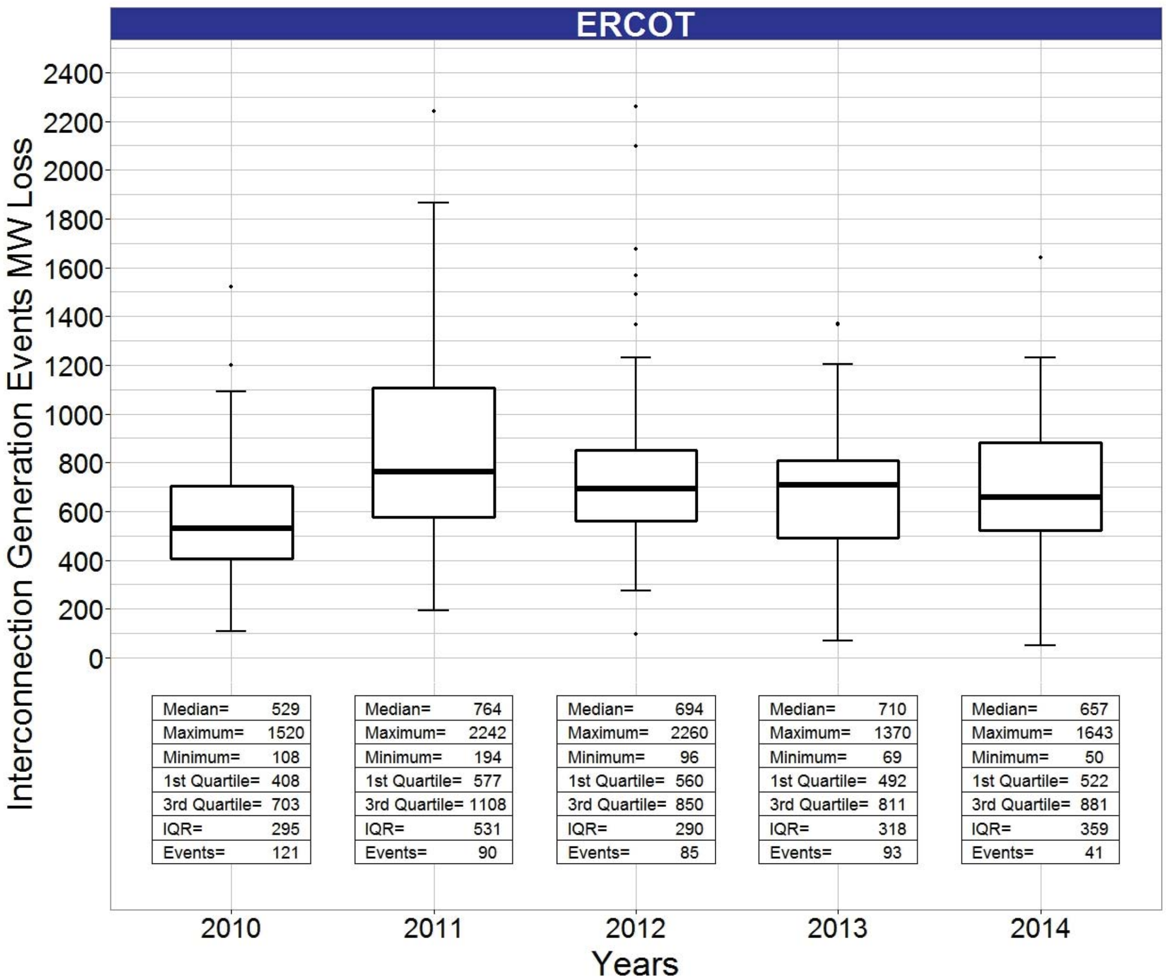
Date: October 15, 2013

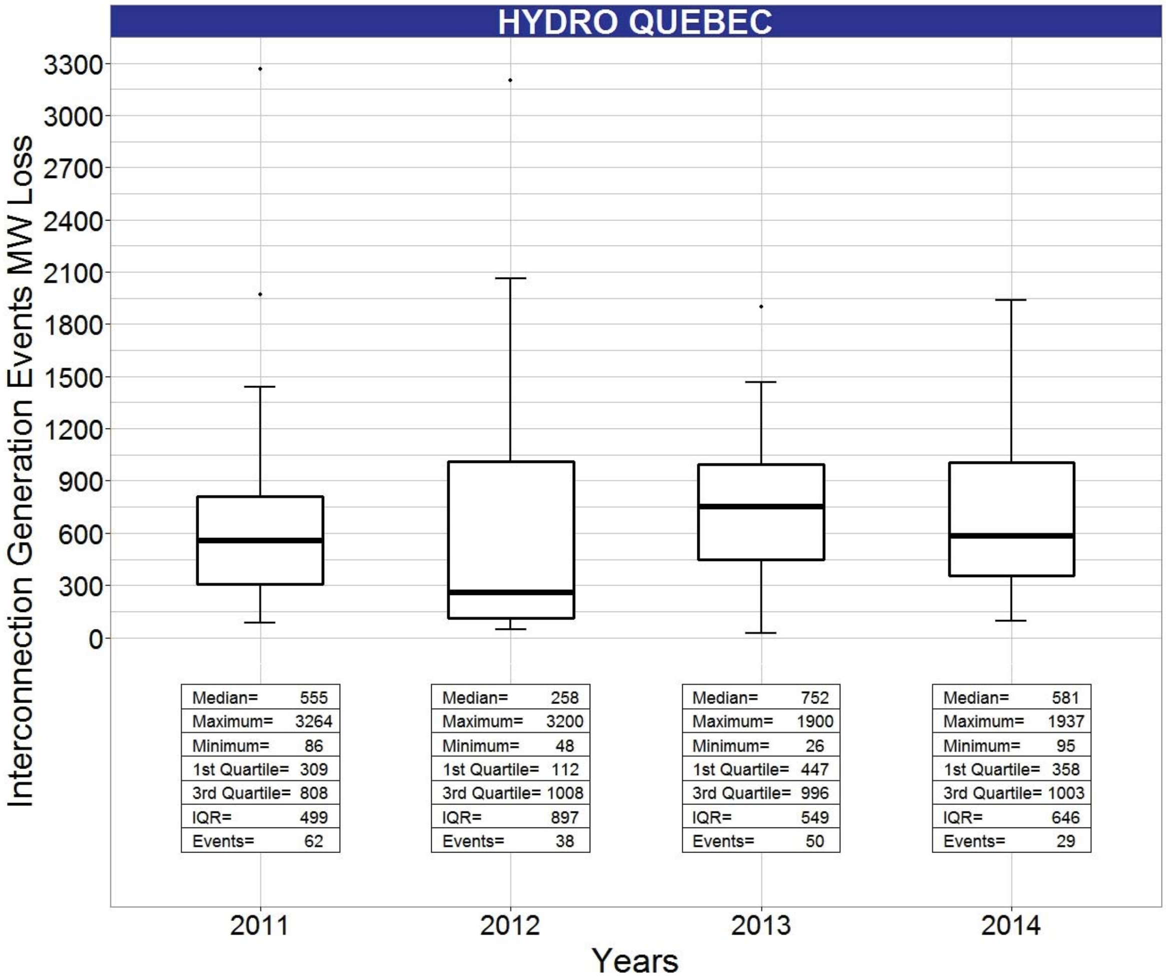
CERTS

CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Interconnection Generation Events MW Loss
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

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[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority’s ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, “significant” losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

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[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

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[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- Example 1

  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- Example 2

  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- Example 3

  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BAL-002-2 Background Document

September~~July~~ 2015

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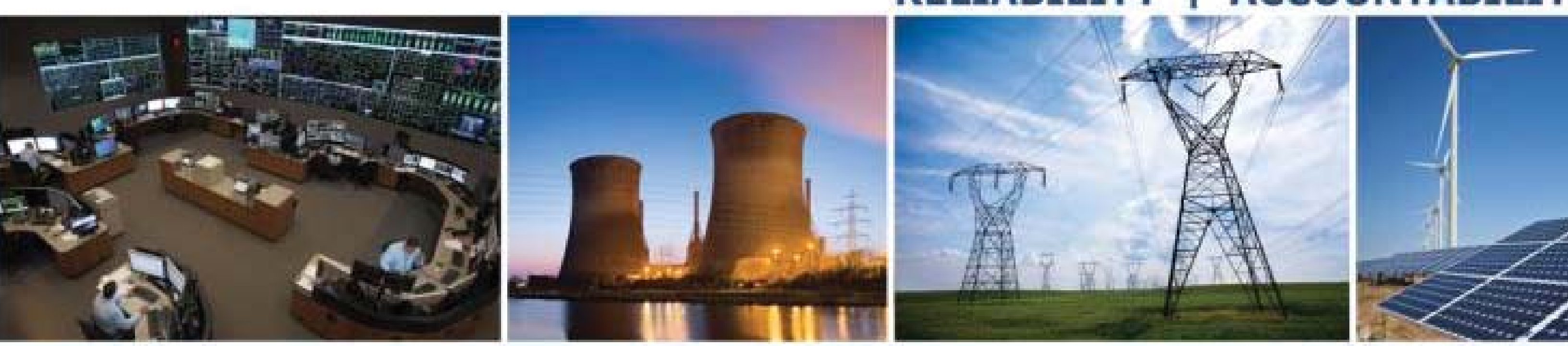

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Introduction

The revision to NERC Policy Standards in 1996 created a Disturbance Control Standard (DCS). It replaced B1 [Area Control Error (ACE) must return to zero within 10 minutes following a disturbance] and B2 (ACE must start to return to zero in 1 minute following a disturbance) with a standard that states: ACE must return to either zero or a pre-disturbance value of ACE within 15 minutes following a reportable disturbance. Balancing Authorities were required to report all disturbances equal to or greater than 80% of the Balancing Authority's Most Severe Single Contingency (MSSC).

BAL-002 was created to replace portions of Policy 1. It measures the ability of an applicable entity to recover from a reportable event with the deployment of reserve. The reliable operation of the interconnected power system requires that adequate capacity and energy be available to maintain scheduled frequency and avoid loss of firm load following loss of transmission or generation contingencies. This capacity (Contingency Reserve) is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment. The design of BAL-002 and Policy 1 was predicated on the Interconnection's operating under normal conditions, and the requirements of BAL-002 assured recovery from single contingency (N-1) events.

This document provides background on the development and implementation of BAL-002-2 - Contingency Reserve for Recovery from a Balancing Contingency Event. This document explains the rationale and considerations for the requirements and their associated compliance information. BAL-002-2 was developed to fulfill the NERC Balancing Authority Controls (Project 2007-05) Standard Authorization Request (SAR), which includes the incorporation of the FERC Order 693 directives. The original SAR, approved by the industry, presumes there is presently sufficient Contingency Reserve in all the North American Interconnections. The underlying goal of the SAR was to update the standard to make the measurement process more objective and to provide information to the Balancing Authority or Reserve Sharing Group, such that the parties would better understand the use of Contingency Reserve to balance resources and demand following a Reportable Balancing Contingency Event.

Currently, the existing BAL-002-1 standard contains Requirements specific to a Reserve Sharing Group which the drafting team believes are commercial in nature and a contractual arrangement between the reserve sharing group parties. BAL-002-2 is intended to measure the successful deployment of contingency reserve by responsible entities. Relationships between the entities should not be part of the performance requirements, but left up to a commercial transaction.

Clarity and specifics are provided with several new definitions. Additionally, the BAL-002-2 eliminates any question about who is the applicable entity and assures that the applicable entity is held responsible for the performance requirement. The drafting team's goal was to have BAL-002-2 be solely a performance standard. The primary objective of BAL-002-2 is to ensure that the applicable entity is prepared to balance resources and demand and to return its ACE to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

As proposed, this standard is not intended to address events greater than a Responsible Entity's Most Severe Single Contingency. These large multi-unit events, although unlikely, do occur. Many interactions occur during these events and Balancing Authorities (BAs) and Reserve Sharing Groups must react to these events. However, requiring a recovery of ACE within a specific time period is much too simple a methodology to adequately address all of these interactions. The suite of NERC Standards work together to ensure that the Interconnections are operated in a safe and reliable manner. It is not just one standard, rather it is the combination of the BAL-001-2 standard (in which R2 requires operation within an ACE bandwidth based on interconnection frequency), TOP-007, and EOP-002, which collectively address issues when large events occur.

- The Balancing Authority ACE Limit (BAAL) in R2 of BAL-001-2 looks at Interconnection frequency to provide the BA a range in which the BA should strive to operate as well as a 30-minute period to address instances when the BA is outside of that range. If an event larger than the BA's MSSC occurs, the BAAL will likely change to a much tighter control limit based on the change in interconnection frequency. The 30-minute limit under the BAAL allows the BA (and its RC) time to quickly evaluate the best course of action and then react in a reasonable manner. BAAL also ensures the Responsible Entity balances resources and demand when events occur of less magnitude than a Reportable Balancing Contingency. In addition R1 of BAL-001-2 requires the BA to respond to assure Control Performance Standard 1 (CPS1) is met. This may prompt the BA to respond in some circumstances in less than 10 minutes.
- The TOP-007 standard addresses transmission line loading. Members of the BAL-002-2 drafting team are aware of instances (typically N-2 or less) that could cause transmission overloads if certain units were lost and reserves responded.
- Under EOP-002, if the BA does not believe that it can meet certain parameters, different rules are implemented.

Because of the potential for significant unintended consequences that could occur under a requirement to activate all reserves, the drafting team recommends to the industry that the revised BAL-002-2 address only events which are planned for (N-1) and not any loss of resource(s) that would exceed MSSC. Therefore, the definitions and Requirements under BAL-002-2 exclude events greater than the MSSC. This provides clarity of Requirements, supports

reliable operation of the Bulk Electric System and allows other standards to address events of greater magnitude and complexity.

Within NERC's State of Reliability Report, ALR2-5 "Disturbance Control Events Greater Than the Most Severe Single Contingency" has been tracked and reported since 2006. For the period 2006 to 2011 there were 90 disturbance events that exceeded the MSSC, with the highest in any given year being 24 events. Evaluation of the data illustrates events greater than MSSC occur very infrequently, and the drafting team believes their exclusion will not have any adverse impact on reliability.

The metric reports the number of DCS events greater than MSSC, regardless of the size of a Balancing Authority or RSG and of the number of reporting entities within a Regional Entity. A small Balancing Authority or RSG may have a relatively small MSSC. As such, a high number of DCS events greater than MSSC may not indicate a reliability problem for the reporting Regional Entity, but may indicate an issue for the respective Balancing Authority or RSG. In addition, events greater than MSSC may not cause a reliability issue for a BA, RSG or Regional Entity that has more stringent standards which require contingency reserve greater than MSSC.

Background

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Balancing Contingency Event

BAL-002-2 applies during real-time operations to ensure the Balancing Authority or Reserve Sharing Group balance resources and demand by returning its Area Control Error to defined values following a Reportable Balancing Contingency Event.

The drafting team included a specific definition for a Balancing Contingency Event to eliminate any confusion and ambiguity. The prior version of BAL-002 was broad and could be interpreted in various ways leaving the ability to measure compliance in the eye of the beholder. Including the specific definition allows the Responsible Entity to fully understand how to perform and meet compliance. Also, FERC Order 693 (at P355) directed entities to include a Requirement that measures response for any event or contingency that causes a frequency deviation. By developing a specific definition that depicts the events causing an unexpected change to the Responsible Entity's ACE, the necessary response requirements assure the intent of the FERC requirement is met.

The definitions of Reportable Balancing Contingency Event and Contingency Event Recovery Period work together to specify the timing requirements for recoveries from Reportable Balancing Contingency Events. A Balancing Contingency Event that is not a Reportable Balancing Contingency Event may impact the compliance requirement for the Reportable Balancing Contingency Event which occurs after it, because the megawatts lost for both may exceed the Most Severe Single Contingency. Also, a subsequent Balancing Contingency Event may occur during the Contingency Event Recovery Period of a Reportable Balancing Contingency Event, affecting the ACE recovery requirement of the initial event. The drafting team struggled with associating any specific time window for the megawatt loss to occur within for an event to qualify as a Balancing Contingency Event. The term sudden implies an unexpected occurrence in the definition of a Balancing Contingency Event, and the Responsible Entity should use its best judgment in applying any time criterion to Balancing Contingency Events that do not qualify as Reportable Balancing Contingency Events.

Most Severe Single Contingency

The Most Severe Single Contingency (MSSC) term has been widely used within the industry; however, it has never been defined. In order to eliminate a wide range of definitions, the drafting team has included a specific definition designed to fulfill the needs of the standard. In addition, in order to meet FERC Order No. 693 (at P356), to develop a continent-wide contingency reserve policy, it was necessary to establish a definition of MSSC.

When an entity determines its MSSC, the review needs to include the largest loss of resource that might occur for either generation or transmission loss. If the loss of transmission causes the loss of generation and load, the size of that event would be the net change. Since the size of an event where both load and generation are lost due to the loss of the transmission would be less than just the loss of the generator, this event is unlikely to be the entity's MSSC. Also, note here that the drafting team removed the previous requirement to review the MSSC at least annually. An entity should know what its MSSC is at all times. Therefore, an annual review is no longer required

Contingency Reserve

Most system operators generally have a good understanding of the need to balance resources and demand and return their Area Control Error to defined values following a Reportable Balancing Contingency Event. However, the existing Contingency Reserve definition is focused primarily on generation and not sufficiently on Demand-Side Management (DSM). In order to meet FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for contingency reserve, the drafting team elected to expand the definition of Contingency Reserve to explicitly include capacity associated with DSM.

Additionally, conflict existed between BAL-002 and EOP-002 as to when an entity could deploy or restore its contingency reserve. EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations (BAL-002) into emergency operations (EOP-002),

this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken.

To eliminate the possible conflict and to assure BAL-002 and EOP-002 work together and complement each other, the drafting team clarified the existing definition of Contingency Reserve. The conflict arises since the actions required by Energy Deficient Entities before declaring either an Energy Emergency Alert 2 or an Energy Emergency Alert 3 include deployment of all Operating Reserve which includes Contingency Reserve. Conversely, an Energy Deficient Entity may need to declare either an Energy Emergency Alert 2 or an Energy Emergency Alert 3, before incurring a Balancing Contingency Event. The definition of Contingency Reserve now allows for deploying capacity to respond to a Balancing Contingency Event and other contingency requirements such as Energy Emergency Alerts. Readiness to reduce Firm Demand during the Contingency Reserve Restoration Period during an Energy Emergency Alert should another Contingency Event occur is proposed for inclusion in the definition of Contingency Reserve. The Responsible Entity should have processes and procedures for direct control over the Firm Demand in place for it to be considered Contingency Reserves prior to the event during an Energy Emergency Alert.

For additional technical justification for exemption from R1 to facilitate transitioning from normal operations into emergency operations please refer to Attachment 2.

Reserve Sharing Group Reporting ACE

The drafting team elected to include this definition to provide clarity for measurement of compliance of the appropriate Responsible Entity. Additionally, this definition is necessary since the drafting team has eliminated R5.1 and R5.2 that are in the existing standard. R5.1 and R5.2 mix definitions with performance. The drafting team has included all the performance requirements in the proposed standards R1 and R2, and therefore has added the definition of Reserve Sharing Group Reporting ACE.

Other Definitions

Other definitions have been added or modified to assure clarification within the standard and requirements.

Rationale by Requirement

Requirement 1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if:

1.3..1 the Responsible Entity ~~is~~:

- is a Balancing Authority experiencing a Reliability Coordinator declared Energy Emergency Alert Level or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- ~~the Responsible Entity~~ has depleted its Contingency Reserve to a level below its Most Severe Single Contingency

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Background and Rationale

Requirement R1 reflects the operating principles first established by NERC Policy 1. Its objective is to assure the Responsible Entity balances resources and demand and returns its Reportable Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

By including new definitions, and modifying existing definitions, and the above R1, the drafting team believes it has successfully fulfilled the requirements of FERC Order No. 693 (at P 356) to include a requirement that explicitly allows DSM to be used as a resource for Contingency Reserve. It also recognizes that the loss of transmission as well as generation may require the deployment of Contingency Reserve.

Additionally, R1 is designed to assure the applicable entity uses reserve to cover a Reportable Balancing Contingency Event or the combination of any previous Balancing Contingency Events that have occurred within the specified period, to address the Order's concern that the applicable entity is responding to events and performance is measured. The Reportable Balancing Contingency Event definition, along with R1, allows for measurement of performance.

In addition, the standard drafting team (SDT) through R1 Part 1.3 has clearly identified when R1 is not applicable. By including R1 Part 1.3.1, the proposed standard eliminates the existing conflict with the EOP Standards and further addresses the outstanding interpretation. By clearly stating when R1 is not applicable or does not apply, it eliminates any auditor interpretation and allows the Responsible Entity to perform the function in a reliable manner. Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to load while managing reliability. Also, the SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

The drafting team used data supplied by the Consortium for Electric Reliability Technology Solutions (CERTS) to help determine all events that have an impact on frequency. Data that was compiled by CERTS to provide information on measured frequency events is presented in Attachment 1. Analyzing the data, reveals events of 100 MW or greater would capture all frequency events for all interconnections. However, at a 100 MW reporting threshold, the

number of events reported would significantly increase with no reliability gain since 100 MW is more reflective of the outlying events, especially on larger interconnections.

The goal of the drafting team was to design a continent-wide standard to capture the majority of the events that impact frequency. After reviewing the data and industry comments, the SDT elected to establish reporting threshold minimums for each respective Interconnection. This assures the requirements of FERC Order No. 693 are met. The reportable threshold was selected as the lesser of 80% of the applicable entity's Most Severe Single Contingency or the following values for each respective Interconnection:

- Eastern Interconnection – 900 MW
- Western Interconnection – 500 MW
- ERCOT – 800 MW
- Quebec – 500 MW

Additionally, the drafting team used only loss of resource events for purposes of determining the above thresholds.

Violation Severity Levels

In the Violation Severity Levels for Requirement R1, the impact of the Responsible Entity recovering from a Reportable Balancing Contingency Event depends on the percentage of desired recovery achieved.

Compliance Calculation

It is important to note that R1 adjusts the required recovery value of Reporting ACE for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. However, to determine compliance score for compliance with R1, the measured contingency reserve response (instead of the required recovery value of Reporting ACE) is adjusted for any other Balancing Contingency Events that occur during the Contingency Event Recovery Period. Both methods of adjustment are mathematically equivalent. Accordingly, the measured contingency reserve response is computed and compared with the MW lost as follows (assuming all resource loss values, i.e. Balancing Contingency Events, are positive) to measure compliance[1]:

- The measured contingency reserve response is equal to one of the following:

[1] In adjusting for the adverse impact of rapidly succeeding (i.e. "near") Events on a Responsible Entity's Recovery from an Event, the SDT thought it more prudent to adjust for future near Events rather than for past near Events because the future Events place an added burden on performance, while adjusting for the past Events instead lowers the performance requirement. To adjust for both future and past Events amounts to double dealing because an Event is subsequent to a prior near Event, and both Events would be serving to relieve Recovery from each other. The SDT allowed only for the extreme case of exempting from recovery prior near Events that combined exceed MSSC.

- If the Pre-Reportable Contingency Event ACE Value is greater than or equal to zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of the subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event.
- If the Pre-Reportable Contingency Event ACE Value is less than zero, then the measured contingency reserve response equals (a) the megawatt value of the Reportable Balancing Contingency Event plus (b) the most positive ACE value within its Contingency Event Recovery Period (and following the occurrence of the last subsequent event, if any) plus (c) the sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event, minus (d) the Pre-Reportable Contingency Event ACE Value.

• Compliance is computed as follows on CR Form 1 in order to document all Balancing Contingency Events used in compliance determination:

- If the measured contingency reserve response is greater than or equal to the megawatts lost, then the Reportable Balancing Contingency Event Compliance equals 100 percent.
- If the measured contingency reserve response is less than or equal to zero, then the Reportable Balancing Contingency Event Compliance equals 0 percent.
- If the measured contingency reserve response is less than the megawatts lost but greater than zero, then the Reportable Balancing Contingency Event Compliance equals 100% * (1 – ((megawatts lost – measured contingency reserve response) / megawatts lost)).

The above computations can be expressed mathematically in the following 5 sequential steps, labeled as [1-5], where:

ACE_BEST – most positive ACE during the Contingency Event Recovery Period occurring after the last subsequent event, if any (MW)

ACE_PRE - Pre-Reportable Contingency Event ACE Value (MW)

COMPLIANCE - Reportable Balancing Contingency Event Compliance percentage (0 - 100%)

MEAS_CR_RESP - measured contingency reserve response for the Reportable Balancing Contingency Event (MW)

MSSC – Most Severe Single Contingency (MW)

MW_LOST - megawatt loss of the Reportable Balancing Contingency Event (MW)

SUM_SUBSQ - sum of the megawatt losses of subsequent Balancing Contingency Events occurring within the Contingency Event Recovery Period of the Reportable Balancing Contingency Event (MW)

If ACE_PRE is greater than or equal to 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ **[1]**

If ACE_PRE is less than 0, then

MEAS_CR_RESP = MW_LOST +ACE_BEST + SUM_SUBSQ – ACE_PRE **[2]**

If MEAS_CR_RESP is greater than or equal to MW_LOST, then

COMPLIANCE = 100 **[3]**

If MEAS_CR_RESP is less than or equal to 0, then

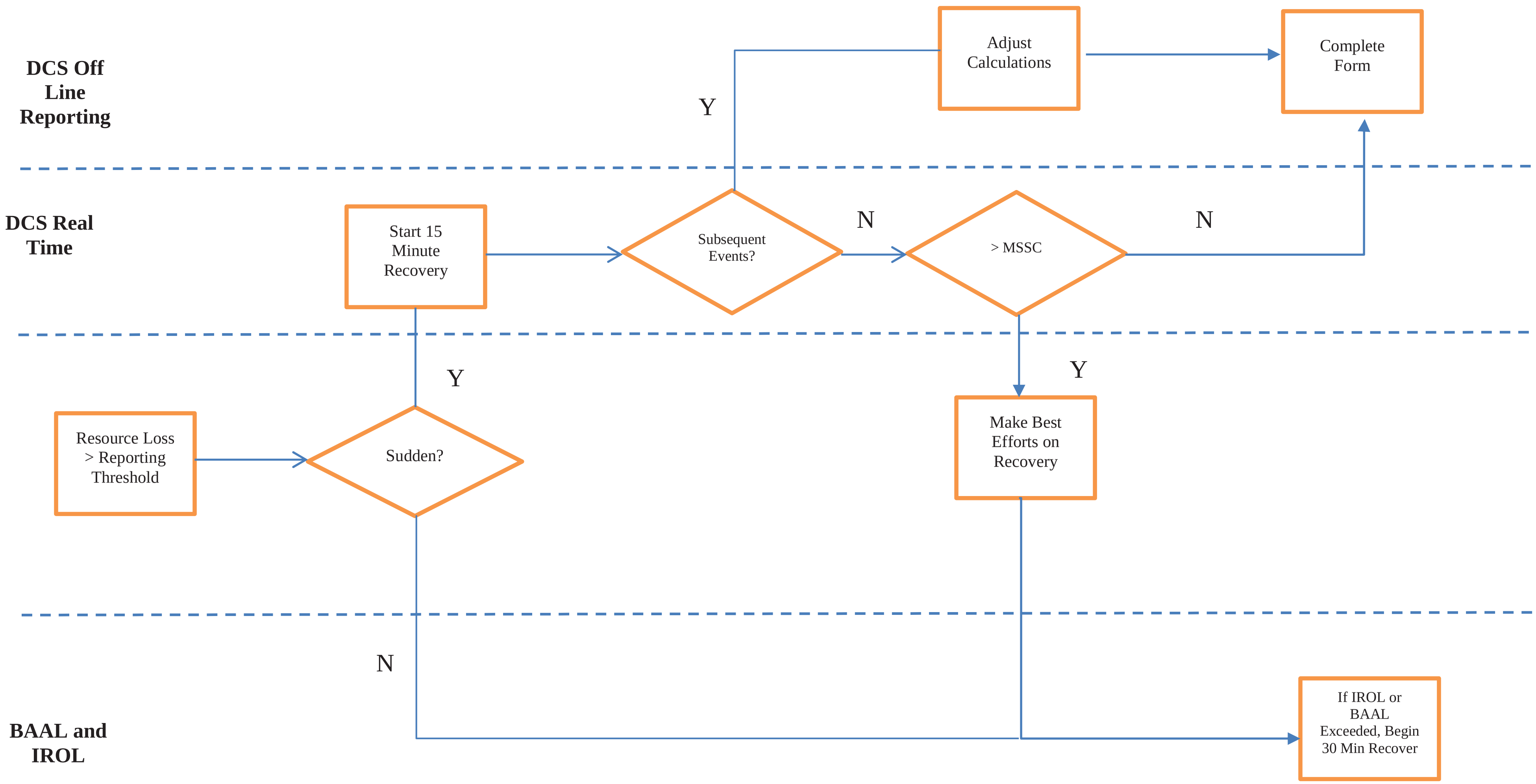
COMPLIANCE = 0 **[4]**

If MEAS_CR_RESP is greater than 0, and, MEAS_CR_RESP is less than MW_LOST, then

COMPLIANCE = 100 * (1 – ((MW_LOST – MEAS_CR_RESP)/ MW_LOST)) **[5]**

The Decision Tree flow diagram for DCS below, provides a visualization of the logic flow for a Reportable Balancing Contingency Event. It includes decision blocks for initial event determination, subsequent event determination, and checking for MSSC exceedance which should assist the Responsible Entity with Event Recovery and analysis.

Decision Tree for DCS



Requirement 2

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Background and Rationale

R2 establishes a uniform continent-wide contingency reserve policy in the form of a requirement that a Responsible Entity implement an Operating Plan that assures Contingency Reserve be at least equal to the applicable entity's Most Severe Single Contingency and a definition of Most Severe Single Contingency. Its goal is to assure that the Responsible Entity will have sufficient Contingency Reserve that can be deployed to meet R1.

FERC Order 693 (at P356) directed BAL-002 to be developed as a continent-wide contingency reserve policy. R2 fulfills the requirement associated with the required amount of contingency reserve a Responsible Entity must have available to respond to a Reportable Balancing Contingency Event. Within FERC Order 693 (at P336) the Commission noted that the appropriate mix of operating reserve, spinning reserve and non-spinning reserve should be addressed. However, the Order predated the approval of the new BAL-003, which addresses frequency responsive reserve and the amount of frequency response obligation. With the development of BAL-003, and the associated reliability performance requirement, the SDT believes that, with R2 of BAL-002 and the approval of BAL-003, the Commission's goals of a continent-wide contingency reserves policy is met. The suites of BAL standards (BAL-001, BAL-002, and BAL-003) are all performance-based. With the suite of standards and the specific requirements within each respective standard, a continent-wide contingency policy is established.

The Responsible Entity's Operating Plan will address the process by which Contingency Reserves greater than or equal to the Most Severe Single Contingency are available in Real-time. Once an entity utilizes its contingency reserve, Requirement R3 addresses restoration of the reserves.

Requirement 3

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration period resets the beginning of the Contingency Event Recovery Period.

Background and Rationale

Requirement R3 establishes the restoration of Contingency Reserves following Reportable Balancing Contingency Events. This requirement addresses the need to be prepared for future Balancing Contingency Events. Contingency Reserves must be restored to at least the minimum required amount, the Most Severe Single Contingency, to assure that the next event for which an entity plans is expected to be covered if the event occurs. Contingency Reserves must be restored within the Contingency Reserve Restoration Period which is defined as a period not exceeding 90 minutes following the end of the Contingency Event Recovery Period, which is 15 minutes.

Attachment 1

NERC Interconnections 2009-2013

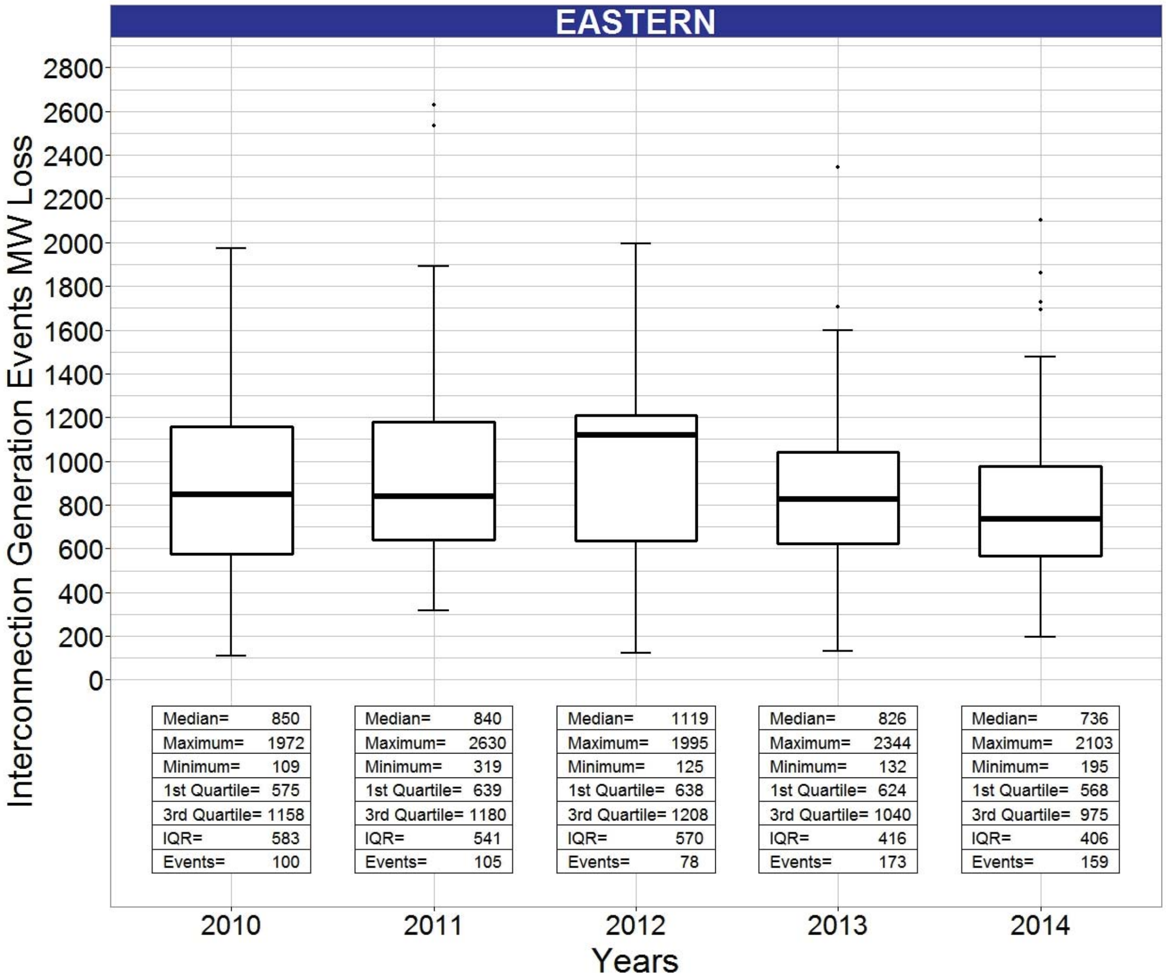
Frequency Events Loss MW Statistics

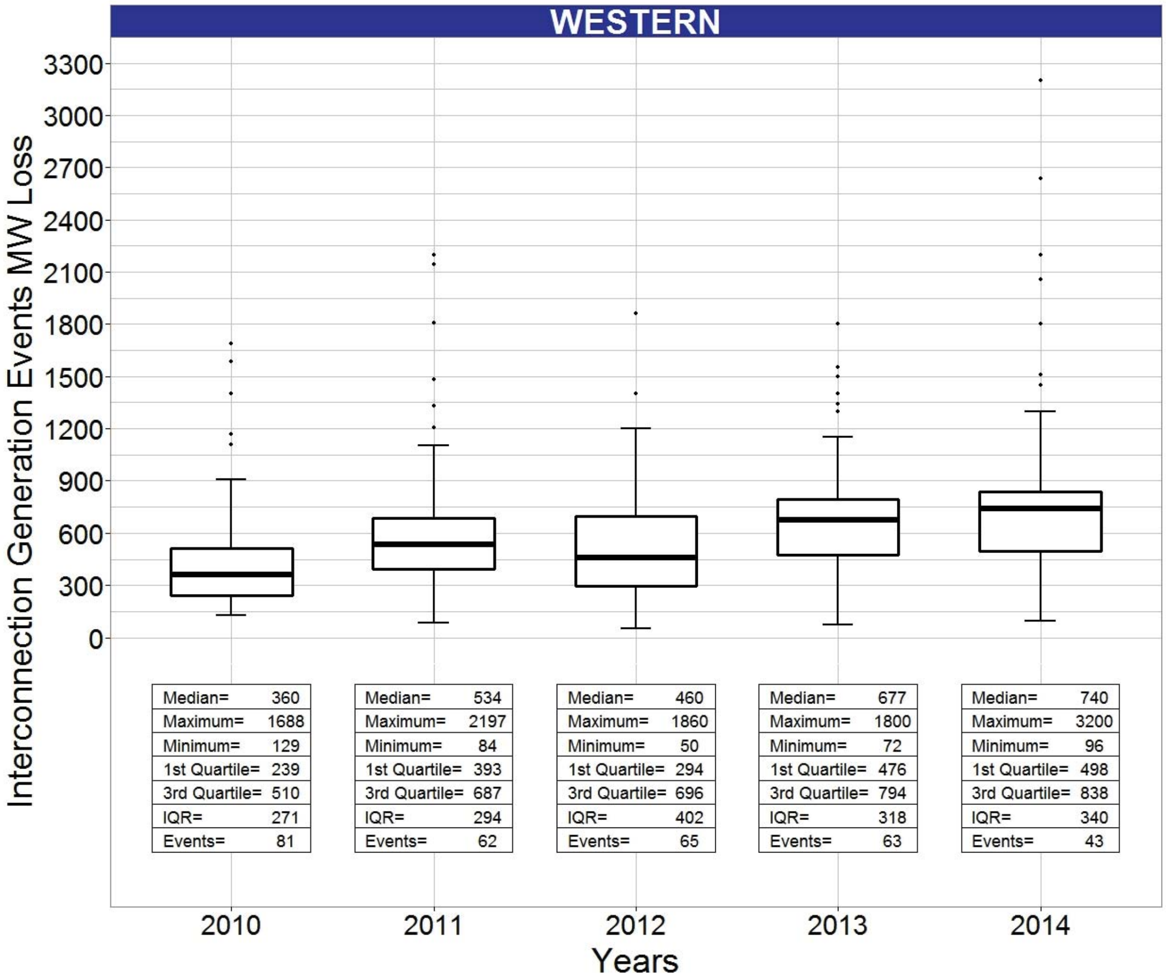
For: NERC BARC Standard Drafting Team

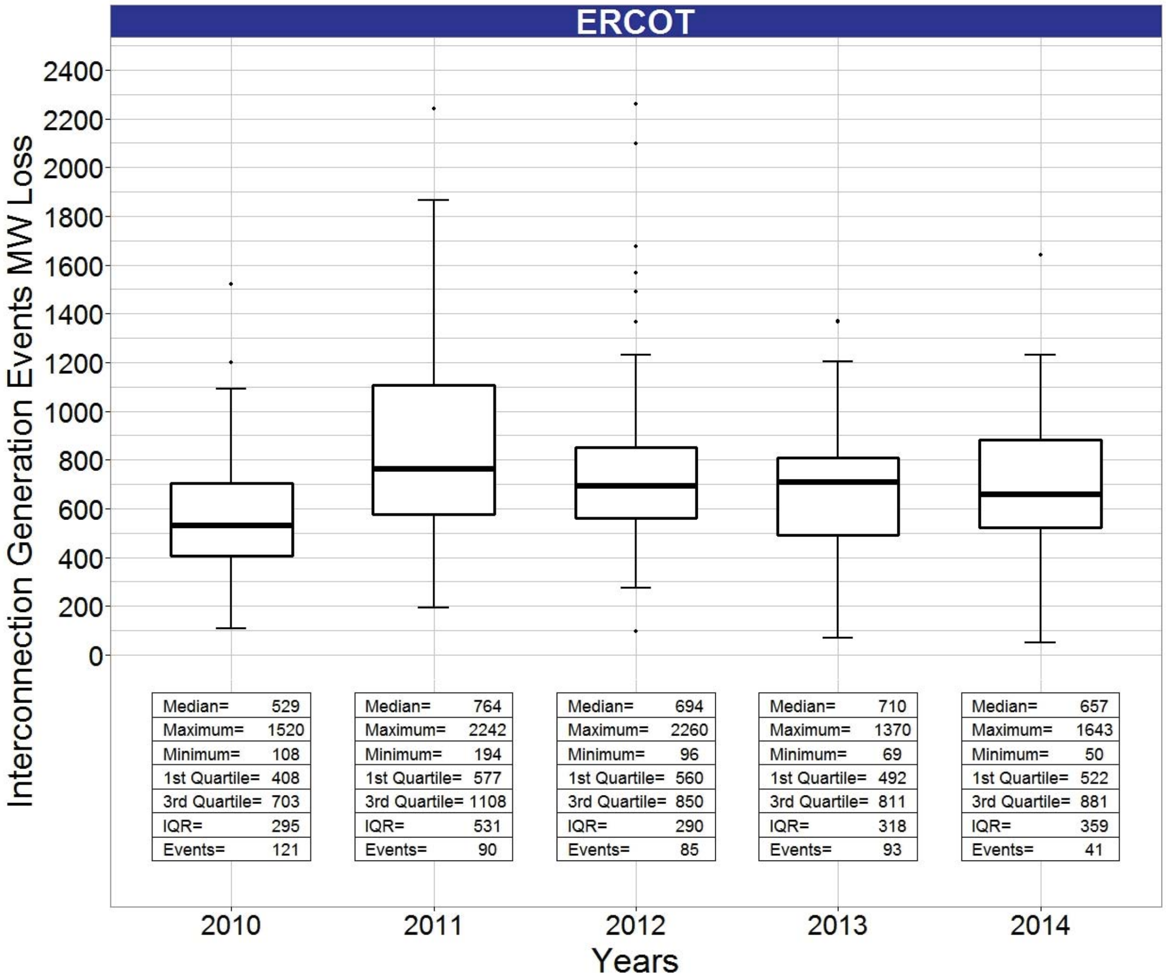
Prepared by: CERTS

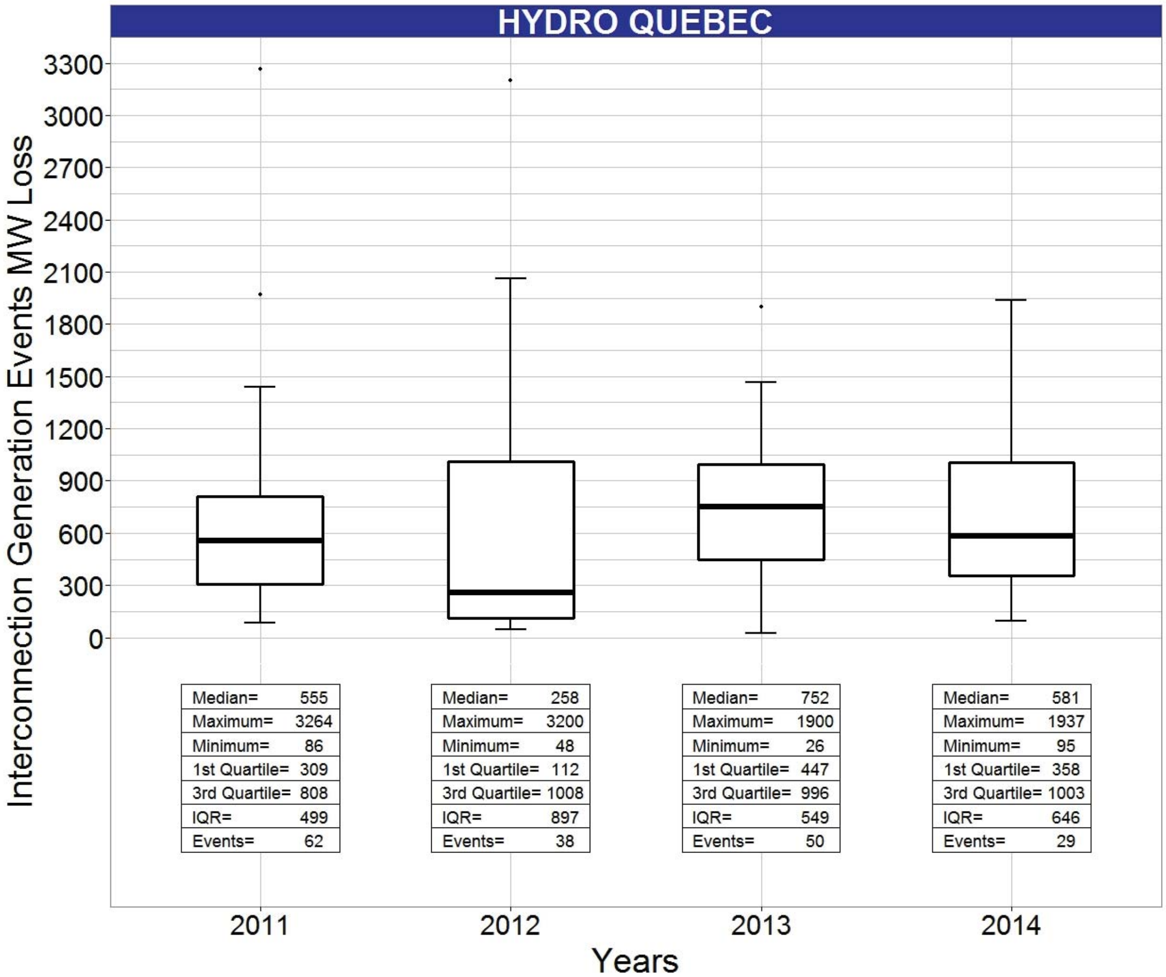
Date: October 15, 2013

CERTS
Consortium for Electric Reliability Technology Solutions


EASTERN
Interconnection Generation Events MW Loss
2800
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 850
Maximum= 1972
Minimum= 109
1st Quartile= 575
3rd Quartile= 1158
IQR= 583
Events= 100
Median= 840
Maximum= 2630
Minimum= 319
1st Quartile= 639
3rd Quartile= 1180
IQR= 541
Events= 105
Median= 1119
Maximum= 1995
Minimum= 125
1st Quartile= 638
3rd Quartile= 1208
IQR= 570
Events= 78
Median= 826
Maximum= 2344
Minimum= 132
1st Quartile= 624
3rd Quartile= 1040
IQR= 416
Events= 173
Median= 736
Maximum= 2103
Minimum= 195
1st Quartile= 568
3rd Quartile= 975
IQR= 406
Events= 159
2010
2011
2012
2013
2014
Years


WESTERN
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 360
Maximum= 1688
Minimum= 129
1st Quartile= 239
3rd Quartile= 510
IQR= 271
Events= 81
Median= 534
Maximum= 2197
Minimum= 84
1st Quartile= 393
3rd Quartile= 687
IQR= 294
Events= 62
Median= 460
Maximum= 1860
Minimum= 50
1st Quartile= 294
3rd Quartile= 696
IQR= 402
Events= 65
Median= 677
Maximum= 1800
Minimum= 72
1st Quartile= 476
3rd Quartile= 794
IQR= 318
Events= 63
Median= 740
Maximum= 3200
Minimum= 96
1st Quartile= 498
3rd Quartile= 838
IQR= 340
Events= 43
2010
2011
2012
2013
2014
Years


ERCOT
Interconnection Generation Events MW Loss
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Median= 529
Maximum= 1520
Minimum= 108
1st Quartile= 408
3rd Quartile= 703
IQR= 295
Events= 121
Median= 764
Maximum= 2242
Minimum= 194
1st Quartile= 577
3rd Quartile= 1108
IQR= 531
Events= 90
Median= 694
Maximum= 2260
Minimum= 96
1st Quartile= 560
3rd Quartile= 850
IQR= 290
Events= 85
Median= 710
Maximum= 1370
Minimum= 69
1st Quartile= 492
3rd Quartile= 811
IQR= 318
Events= 93
Median= 657
Maximum= 1643
Minimum= 50
1st Quartile= 522
3rd Quartile= 881
IQR= 359
Events= 41
2010
2011
2012
2013
2014
Years


HYDRO QUEBEC
Interconnection Generation Events MW Loss
3300
3000
2700
2400
2100
1800
1500
1200
900
600
300
0
Median= 555
Maximum= 3264
Minimum= 86
1st Quartile= 309
3rd Quartile= 808
IQR= 499
Events= 62
Median= 258
Maximum= 3200
Minimum= 48
1st Quartile= 112
3rd Quartile= 1008
IQR= 897
Events= 38
Median= 752
Maximum= 1900
Minimum= 26
1st Quartile= 447
3rd Quartile= 996
IQR= 549
Events= 50
Median= 581
Maximum= 1937
Minimum= 95
1st Quartile= 358
3rd Quartile= 1003
IQR= 646
Events= 29
2011
2012
2013
2014
Years

Attachment 2

Technical Justification for Applicability of BAL-002 During Emergency Alerts

Technical Justification for Applicability of BAL-002 During Energy Emergency Alerts

I. INTRODUCTION

The Balancing Authority Reliability-based Controls standard drafting team (BARC SDT) has identified a conflict between NERC Reliability Standards BAL-002 and EOP-002 that unnecessarily requires arbitrary interruption of Firm Load. In order to address this issue, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an Energy Emergency Alert (EEA) event where the EEA process requires the use of Contingency Reserve to maintain load service.[2] This document provides support for this recommendation and an overview of reliable frequency management on the North American Interconnections.

II. BACKGROUND

Reliably balancing an Interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.

Reliability Standard BAL-002 applies during the real-time operations time horizon and addresses the balancing of resources and demand following a disturbance. Reliability Standard EOP-002 also applies during the real-time operations time horizon and addresses capacity and energy emergencies. Given that an entity and/or event can transition suddenly from normal operations into emergency operations (EOP-002) where Contingency Reserve maintained under BAL-002 may be utilized to serve Firm Load, this transitional seam must be explicitly addressed in order to provide clarity to responsible entities regarding the actions to be taken. The proposed applicability of BAL-002 is designed to address this issue.

III. LEGACY REQUIREMENTS

The Resource and Demand Balancing (BAL) standards include both requirements that have a sound technical basis and legacy requirements that the industry has used for years but fail to

[2] The proposed applicability section states: "Applicability is determined on an individual Reportable Balancing Contingency Event basis, but the Responsible Entity is not subject to compliance during periods when the Responsible Entity is in an Energy Emergency Alert Level under which Contingency Reserves have been activated."

have a sound technical basis. NERC began replacing these legacy requirements with technically based requirements starting with the Control Performance Standard1 (CPS1). Both Control Performance Standard2 (CPS2) and the Disturbance Control Standard (DCS) remain in the legacy category. The following are specific concerns associated with these requirements.

- When CPS1 was implemented to replace A1/A2, previous requirements were modified so that CPS1 would apply at all times including the (disturbance) periods where DCS is applicable, not just during normal operations/periods. So DCS is not the only standard governing disturbance conditions.
- The Disturbance Control Standard (DCS) and its precursor B1/B2 have been unique in requiring immediate action by the Balancing Authority (BA), in this case to address unexpected imbalances within defined limits.
- DCS, albeit results-based in its current form, was initially designed to measure the utilization of Contingency Reserve to address a loss of resource within the defined limits. In its results-based form it assumed that implementing sufficient Contingency Reserves as needed to comply with the recovery requirement would be a reasonably equitable minimum quantity for all BAs participating in interconnected operation.
- DCS is based upon ACE recovery to the lower of pre-disturbance ACE or zero. A Balancing Authority which might be under-generating prior to a generation loss, could lose a generating unit and under DCS be deemed compliant if it returned ACE to its pre-disturbance state, though it could still be depressing Interconnection frequency.
- As DCS recovery from a reportable event must occur within a 15-minute period, it is possible for a Balancing Authority's ACE to again go negative after that time, with a similar impact on Interconnection frequency.
- Since CPS2 allows a BA to be unaccountable for approximately 74 hours of operation in a 31-day month, an imbalance condition may persist and negatively impact Interconnection frequency for many hours[3].
- When ACE is modulated by frequency, "significant" losses are defined not only by the size of the event causing an ACE deviation, but also contingent on the deviation of Interconnection frequency from Scheduled Frequency.

IV. TIE-LINE BIAS FREQUENCY CONTROL AND ACE

[3] Reliability-Based Control v3, Standard Authorization Request Form, November 7, 2007.

Tie-Line Bias Frequency Control is implemented on the North American Interconnections through the use of the ACE Equation.[4] In general, ACE is the term used to determine the load-generation imbalance that is being contributed by each Balancing Authority (BA) on an Interconnection. ACE is a powerful indicator, because it indicates the imbalance within the boundaries of a single BA, thus defining the Secondary Control responsibilities for that BA and, therefore, the control action that would return ACE to zero. ACE includes the Frequency Bias Setting term, which allows the Primary Frequency Control to be a shared service throughout a multi-BA Interconnection, while assigning to each individual BA the specific responsibilities of maintaining its own Secondary Frequency Control.

In summary, ACE only provides guidance with respect to Secondary Frequency Control and does not indicate or provide any direct measure of Primary Frequency Control, and only reflects the estimated Frequency Response as represented by the Frequency Bias Setting term. NERC Requirements and supporting documentation for Frequency Response (Primary Frequency Control) are included in BAL-003-1 Frequency Response and Frequency Bias Setting standard. More detail on Tie-Line Bias Frequency Control and ACE is attached.[5]

V. CONTROL PERFORMANCE STANDARD1 (CPS1)

Prior to the development of CPS1, the industry assumed that, "It is impossible, however, to use frequency deviation to identify the specific control area (sic, i.e. BA) with the under- or over-generation creating the frequency deviation…".[3] In the 1990's the development of CPS1 demonstrated that not only was it possible to identify the specific BA creating the frequency deviation, but that it is also possible not only to determine the relative contribution by each BA to the magnitude of the frequency deviation[6], but also to determine the relative contribution of each BA to the reliability risk caused by that deviation. In addition, the CPS1 Requirement provided a guarantee: "If all BAs on an interconnection complied with the CPS1 Requirement,

[4] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 1-4, for a derivation of the ACE Equation and the requirements for implementing it that are included in the definition of ACE appearing in the NERC Glossary.

[5] Illian, Howard F., Frequency Control Performance Measurement and Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, December 2010, for a discussion of the history of Frequency Control and Performance Measurement.

[6] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Section 2, pp. 5-10 for a derivation of the CPS1 requirement.

the Root Mean Squared[7] value of the frequency deviation for that Interconnection would be less than the epsilon1[8] frequency deviation limit for that Interconnection."

CPS1 is a rolling annual average of individual measurements each averaged over one-minute, and is assessed monthly. CPS1 measures the covariance between the ACE of a BA and the frequency deviation of the Interconnection which is equal to the sum of the ACEs of all of the BAs. CPS1 has the great value of using the Interconnection frequency to determine the degree to which ACE among the BAs on a multiple BA Interconnection is harming or helping interconnection frequency. Since the frequency deviation is a measured value, the ACE of a BA will directly affect only the CPS1 of the BA with the ACE and not the CPS1 measure of other BAs.

VI. BALANCING AUTHORITY ACE LIMIT (BAAL)

When the Balancing Resources and Demand (BRD) standard drafting team recognized the need for a control measure over a shorter time horizon than either CPS1 (annual) or Control Performance Standard 2[9] (CPS2, monthly) provided, it began looking for a measure that would allow a window for common imbalance events like a unit trip, while providing a limit on how much frequency deviation should be allowed over that short period. After considering numerous alternatives, BAAL was selected as the appropriate short-term measure.[10,11]

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[7] "Root Mean Squared" means the square root of the mean of the squared errors, so that positive and negative errors do not offset each other and any shift in the mean is counted as error.

[8] "Epsilon1" is the frequency deviation limit determined for each North American Interconnection and used by CPS1 to bound the Root Mean Squared frequency deviation. It is 18 mHz on the Eastern, 22.8 mHz on the Western, 30 mHz on the ERCOT, and 21 mHz on the Quebec Interconnections.

[9] Proposed to be replaced by BAAL under BAL-001-2, CPS2 requires the BA to move its ACE within predefined L10 bounds when it is binding (during only 90% of the ten-minute periods per month) without regard to whether such action helps or hurts Interconnection frequency.

[10] Illian, Howard F., Meeting the Discrete Event Measure (DEM) Objectives with the Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 20, 2004.

[11] Illian, Howard F., Setting the Balancing Authority ACE Limit (BAAL) for the NERC Abnormal Operations Measure (AOM), Prepared for the NERC Balancing Resources and Demand Standard Drafting Team, March 28, 2004.

Considerable evaluation and Field Trials have shown that BAAL[12] is a better indicator of contributions to reliability risk of an interconnection than the magnitude of ACE alone. This superiority, like CPS1's, derives from the concurrent use of both ACE and frequency error in the BAAL measure. Thus BAAL captures the relative contribution to reliability by all of the ACEs on an interconnection and indicates where each BA stands relative to its secondary control responsibilities and the current state of the interconnection as indicated by the frequency error for both under- and over-frequency conditions.

VII. INTERACTION BETWEEN STANDARDS

The drafting team has identified as an issue the existence of points where the standards are in conflict with each other. The drafting team has attempted to address the conflicts identified, as follows:

NERC standard EOP-002 requires a BA to use all its reserves during an Energy Emergency Alert 2 (EEA2) or higher. The following language is found in EOP-002 Attachment 1-EOP-002:

> **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

The current BAL-002 specifies a minimum level reserve requirement at all times unless a qualifying event has occurred. The drafting team noted that in the EEA process an entity is driven to request an EEA rarely as the result of a single unit loss. In fact, an EEA declaration by the Reliability Coordinator might result from issues that include no event that would qualify as a Disturbance and the EEA situation could last longer than the reserve recovery period of 90 minutes. For this reason, the drafting team recommends significant changes to the standards in question.

In addition to the identified conflict, other standards can require the activation of contingency reserve. These include other BAL standards, IRO standards and TOP standards. Compared to those standards, the BAL-002 standard provides the least direct measure of reliability. Therefore, an entity should never be conflicted between applying the requirements of BAL-002 and complying with the other standards.

[12] Illian, Howard F., Understanding ACE, CPS1 and BAAL, Prepared for the NERC BARC Standard Drafting Team, September 10, 2010 rev. August 19, 2014, Section 2, pp. 10, for a derivation of the BAAL requirement.

Finally, there is one overarching principal not reflected in the discussion up to this point, namely keeping the lights on if possible. If there is a requirement to bring ACE back no matter what, then that requirement will have the unintended consequence of shedding Firm Load, especially during an EEA. During the EEA process, the expectation is that a BA will have firm load ready to shed in order to meet its reserve requirement under R2 of the proposed BAL-002 standard. However, if the BAL-002 standard also requires the entity to meet R1 during the EEA, entities will shed firm load to restore ACE to its pre-contingency level, regardless of the lack of any reliability issues. In other words, frequency could be settling at or very near 60 Hz, no transmission lines are overloaded as determined by the TOP standards, and the entity is operating within the parameters defined in BAL-001, but firm load would be interrupted simply to bring the entity's ACE back to what it was prior to the loss of the unit. Since the industry has defined reliability as frequency at or near 60 Hz and transmission lines operating within their limits, there is no reason to interrupt firm load.

Instead, the BARC SDT is recommending that Standard BAL-002-2 not be enforceable during an EEA event where the EEA process requires the use of Contingency Reserve to maintain load service. Instead, the Reliability Coordinator, Transmission Operators and the impacted Balancing Authorities should use real-time situational awareness, taking into account issues addressed in BAL-001, BAL-003, the IRO suite of standards and the TOP suite of standards, to determine what actions are appropriate when conditions are abnormal. This process would allow continued load service without arbitrarily requiring interruption of firm load.

This concern arises because the other standards look at specific reliability issues other than just balancing between scheduled and actual interchange. BAL-001-2 and BAL-003-1 look at interconnection frequency to determine whether the Balancing Authority is helping or hurting reliability. During an EEA event, curtailing load to move ACE back to a pre-event level could adversely affect frequency. If frequency goes up from 60 Hz when a Balancing Authority interrupts load, the impact is detrimental to the interconnection. Under the TOP standards, if flows on transmission lines are within the limits specified, there is no need to alter the flows on the transmission system by interrupting load.

Finally, the Reliability Coordinator has a wide area view of the electric system as required under the IRO standards. The IRO standards clearly state the Reliability Coordinator's responsibilities during the EEA process. If the Reliability Coordinator has not identified a reliability concern in its near term operations evaluation, actions such as interruption of firm load should not occur simply to balance load and resources within the BA. During abnormal (emergency) situations, taking significant actions with a narrow view will not be beneficial for Interconnection reliability.

EXAMPLES

- <u>Example 1</u>
  On an usually cold day in February 2011, at 06:22, a Balancing Authority Area (BAA) experienced a 350 MW generation loss when a 750 MW joint ownership unit tripped off-line. Earlier in the day the BAA operator experienced loss of several generating units with a total capacity of 1050 MW, the latest loss being just 38 minutes prior to the 350 MW loss. When the 350 MW event occurred the BAA operator requested reserve/emergency assistance, shed 300 MW of customer load to restore contingency reserve, and requested the RC post an EEA3. The EEA3 was posted. Although the frequency only touched 59.91 Hz, averaging 59.951 Hz in the first minute of the outage, was it really necessary to cut load and leave people in the cold, dark of that morning to restore contingency reserve? Having idle generation, when the Interconnection is operating reliably, does not warrant shedding customer load.
- <u>Example 2</u>
  In June 2012, at 17:08, a BAA experienced an 800 MW generation loss. The BA and the reserve sharing group (RSG) it participates in were in the process of replacing the lost generation when, in the thirteenth minute of the recovery when there were no identified frequency, voltage or loading threats to reliability, the BAA was directed by its Reliability Coordinator (RC) to shed 120 MW of customer load. Although the combined Area Control Error (ACE) of the RSG participants was positive, the RC focused on the ACE of the BAA that lost the generation – which was still negative – ignoring the fact that the Interconnection frequency (59.96 Hz) was above the Frequency Trigger Limit (59.932 Hz). The needless shedding of customer load when system reliability is not threatened attracted the attention of state regulators who were not happy with the action. This demonstrates that focusing solely on a BAA's ACE and not on the true Interconnection reliability indicators can cause actions that do not support reliability.
- <u>Example 3</u>
  In June 2004, at 0741, a series of events led to a generation loss of over 4,600 MW. In spite of the event size, the Interconnection frequency was arrested without triggering automatic underfrequency load shedding, thanks to governor action, frequency sensitive load and deployment of Contingency Reserve (as required by BAL-002). Some transmission elements exceeded their limits for a short time (as permitted by the EOP standards), And, prior to the disturbance, the frequency was in the normal operating range due to automatic generation control (AGC) operation (as required by BAL-001). During the event almost 1,000 MW of interruptible customer load was shed throughout the interconnected systems by devices that automatically operated to protect various parts of the

system (as determined by the TPL and TOP Standards). This demonstrates how the suite of standards defined by NERC work together to efficiently protect the system and minimize customer interruptions.

VIII. CONCLUSIONS

There are important conclusions that can be drawn from this work and the mathematical guarantees that it provides:

- The Disturbance Control Standard (DCS) as currently configured only looks at ACE, the imbalance contribution of a single BA, and does not include a specific frequency error component that indicates the BA's contribution relative to the condition of the interconnection to which the BA is connected.

- As the DCS measure does not have a specific frequency component, compliance to DCS at times conflicts with the overall goal of targeting operation within predefined Interconnection frequency limits. For example, DCS recovery initiated from above Scheduled Frequency has a detrimental impact on Interconnection frequency.

- The focus on ACE alone is insufficient to control frequency on a multiple BA Interconnection. The correlation of the ACEs among the BAs on the Interconnection will affect the quality of frequency control independent of how any individual ACE is controlled.

- Adequate control of Interconnection frequency requires the use of both ACE (individual BA balancing error) and frequency deviation.

- Adequate control of reliability risk on an Interconnection requires the use of ACE, frequency deviation and available frequency response.

- BAAL addresses all events impacting Interconnection frequency, both above and below scheduled frequency.

BAAL addresses all of the above issues in its time domain without requiring response to or measurement of events that fail to raise reliability concerns. For these reasons, the proposed applicability of BAL-002 is a reasonable and technically-justified approach that addresses the seam with EOP-002.

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-002-2, Contingency Reserve for Recovery from a Balancing Contingency Event. 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

[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 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

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-002-2:

There are two requirements in BAL-002-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-002-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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 and approved reliability standards BAL-001-1 and BAL-003-1.
- 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

violation, in itself, 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-002-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. All of the requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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 and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. All of the requirements in BAL-002-2 are assigned a "Medium" VRF. . This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2 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-002-2 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-002-2 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 levels of noncompliance performance.	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.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-002-2 Requirement R3:

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
R3.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	This is similar to the current BAL-002-1 Requirement R3.1. 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 amount of contingency reserve recovered.	Proposed VSLs do not expand on what is required in the requirement. 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-002-2, Contingency Reserve for Recovery from a Balancing Contingency Event. 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

[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 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

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-002-2:

There are two requirements in BAL-002-2. Both requirements were assigned a "Medium" VRF.

VRF for BAL-002-2, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. ~~Both~~All of the requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R2. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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~~, proposed~~ and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. ~~Both~~All of the requirements in BAL-002-2 are assigned a "Medium" VRF. Requirement R2 is similar in scope to Requirement R1. This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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~~, proposed~~ and approved reliability standards BAL-001-1 and BAL-003-1.
- 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 violation, in itself, 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-002-2, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain subrequirements. All of the requirements in BAL-002-2 are assigned a "Medium" VRF. . This is also consistent with other reliability standards (i.e., BAL-001-2, BAL-003-1, etc).
- 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, and approved reliability standards BAL-001-1 and BAL-003-1.
- 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

violation, in itself, 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-002-2 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-002-2 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-002-2 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 levels of noncompliance performance.	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 amount of time the entity is noncompliant.~~.	Proposed VSLs do not expand on what is required in the requirement. The VSLs assigned only consider the amount of time an entity is non-compliant with the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

VSLs for BAL-002-2 Requirement R3:

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
R3.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	This is similar to the current BAL-002-1 Requirement R3.1. 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 amount of contingency reserve recovered.	Proposed VSLs do not expand on what is required in the requirement. 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
BAL-002-2

Final Ballot Open through October 8, 2015

Now Available

A final ballot for **BAL-002-2 – Contingency Reserve for Recovery from Balancing Contingency Event** is open through **8 p.m. Eastern, Thursday, October 8, 2015.**

The standard drafting team (SDT) reviewed the responses received from the previous comment period (July 7 – August 20, 2015). There were several requests for clarification on the SDT's intent for a couple of items in the standard. The SDT has added minor clarifying language to the areas identified by the commenters.

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a vote. All ballot pool members may change their previously cast vote. A ballot pool member who failed to vote during the previous ballot period may vote in the final ballot period. If a ballot pool member does not participate in the final ballot, the member's vote from the previous ballot will be carried over as their vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard here. If you experience any difficulties using the Standards Balloting & Commenting System, contact Wendy Muller.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at EROhelpdesk@nerc.net (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standard will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
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Standards Announcement

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls
BAL-002-2

Final Ballot Results

Now Available

A final ballot for **BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event** concluded **8 p.m. Eastern, Thursday, October 8, 2015**.

The standard received sufficient affirmative votes for approval and voting statistics are listed below. The Ballot Results page provides a link to the detailed results for the ballot.

Ballot
Quorum / Approval
84.28% / 74.61%

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

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BALLOT RESULTS

Ballot Name: 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls BAL-002-2 FN 2 ST
Voting Start Date: 9/29/2015 11:12:55 AM
Voting End Date: 10/8/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 252
Total Ballot Pool: 299
Quorum: 84.28
Weighted Segment Value: 74.61

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	74	1	41	0.732	15	0.268	0	5	13
Segment: 2	9	0.9	4	0.4	5	0.5	0	0	0
Segment: 3	70	1	39	0.78	11	0.22	0	10	10
Segment: 4	25	1	10	0.769	3	0.231	0	9	3
Segment: 5	66	1	33	0.767	10	0.233	0	10	13
Segment: 6	44	1	24	0.8	6	0.2	0	7	7
Segment: 7	0	0	0	0	0	0	0	0	0

Segment: 9	2	0.1	1	0.1	0	0	0	0	1
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	299	6.9	160	5.148	51	1.752	0	41	47

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Negative	N/A
1	Avista - Avista Corporation	Bryan Cox		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Beaches Energy Services	Don Cuevas		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Empire District Electric Co.	Ralph Meyer		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	None	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		None	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Affirmative	N/A
1	IDACORP - Idaho Power Company	Molly Devine		Affirmative	N/A

1	International Transmission Company Holdings Corporation	Michael Moltane	Meghan Ferguson	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	N/A
1	Lincoln Electric System	Doug Bantam		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Alan MacNaughton		Negative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Robert Fox		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A

1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	John Walker		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Sacramento Municipal Utility District	Tim Kelley	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Negative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A

1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Negative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		Affirmative	N/A
2	California ISO	Richard Vine		Negative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	N/A
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	PJM Interconnection,	Mark Holman		Affirmative	N/A

	L.L.C.				
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		None	N/A
3	City of Green Cove Springs	Mark Schultz		Abstain	N/A
3	City of Leesburg	Chris Adkins		Abstain	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Abstain	N/A
3	Florida Power & Light	Summer Esquerre		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Grand River Dam Authority	Jeff Wells		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	None	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		None	N/A
3	Lakeland Electric	Mace Hunter		Abstain	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A

3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	PNM Resources	Michael Mertz		Affirmative	N/A
3	Portland General Electric Co.	Thomas Ward		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Okanogan County	Dale Dunckel		None	N/A
3	Puget Sound Energy, Inc.	Andrea Basinski		Affirmative	N/A

3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tallahassee Electric (City of Tallahassee, FL)	John Williams		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		Affirmative	N/A
3	WEC Energy Group, Inc.	James Keller		Negative	N/A
3	Westar Energy	Bo Jones		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power	Duane Dahlquist		Affirmative	N/A

	Agency				
4	City of Clewiston	Lynne Mila		Abstain	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Abstain	N/A
4	City of Redding	Nick Zettel	Mary Downey	None	N/A
4	City of Winter Park	Mark Brown		None	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Abstain	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Affirmative	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Flathead Electric Cooperative	Russ Schneider		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Abstain	N/A
4	Fort Pierce Utilities Authority	Thomas Parker		Abstain	N/A
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation District	Spencer Tacke		Negative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		Affirmative	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A

4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Negative	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Mary Downey	None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A

5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Dynegy Inc.	Dan Roethemeyer		Negative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Exelon	Vince Catania		Affirmative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble		None	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Abstain	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A

5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	N/A
5	NaturEner USA, LLC	Jamie Lynn Bussin		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Negative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		None	N/A
5	Omaha Public Power District	Mahmood Safi		Abstain	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PowerSouth Energy Cooperative	Tim Hattaway		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Negative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		None	N/A

5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Lewis Pierce		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		Negative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker	Dennis Chastain	Affirmative	N/A
5	U.S. Bureau of Reclamation	Erika Doot		Abstain	N/A
5	Xcel Energy, Inc.	David Lemmons		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Associated Electric	Brian Ackermann		Negative	N/A

	Cooperative, Inc.				
6	Austin Energy	Andrew Gallo		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	City of Redding	Marvin Briggs	Mary Downey	None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Abstain	N/A
6	Florida Municipal Power Pool	Tom Reedy		Abstain	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges		None	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Lower Colorado River Authority	Michael Shaw		Abstain	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel	John Hare	Abstain	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Negative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Jara		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Kenn Backholm		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy	John J. Ciza		Affirmative	N/A

	Marketing				
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Exhibit I

Mapping Document for BAL-002-2

Project 2010-14.1 Mapping Document
Transition of BAL-002-0 to BAL-002-2

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R1	This Requirement has been moved into BAL-002-2 Applicability and "Additional Compliance Information" sections	This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading outages.
BAL-002-0 R2	This requirement has been removed from BAL-002-2	This requirement falls under the Paragraph 81 rules. This requirement defines a commercial agreement between the BA involved in the RSG. This requirement does not provide for a reliability outcome and if violated would not cause separation, instability or cascading
BAL-002-0 R3	Requirement R1 and R2	This requirement was broken apart. The requirement was defining two separate actions; 1) to require activation of Contingency Reserves, and 2) to require having Contingency Reserves equal to its MSSC.
BAL-002-0 R4	This Requirement has been moved into BAL-002-2 Requirement R1 and into the "Contingency Event Recovery Period" definition.	Requirement R1 mandates recovery from a Reportable Balancing Contingency Event. A portion of this requirement was defining the timing for recovery from an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Standard: BAL-002-0 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-002-0 R5	This Requirement has been moved into BAL-002-2 Requirement R1 and "Reserve Sharing Group Reporting ACE" definition.	A portion of this requirement was defining how a RSG calculates its ACE. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.
BAL-002-0 R6	This Requirement has been moved into the BAL-002-2 Requirement R3 and "Contingency Event Restoration Period" definition.	Requirement R3 mandates restoration of Contingency Reserve following a Balancing Contingency Event. A portion of this requirement was defining the timing for restoration of Contingency Reserve after an event. This has now been defined and has been proposed to be added to the NERC Glossary of Terms.

Exhibit J

Mapping Document for EOP-011

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies. **R3.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired R3.4 under Criteria A and B1 of Paragraph 81 guidelines.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.		1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **Retirements:** **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		• COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.		reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to the Reliability Coordinator within a time period specified by its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Operation Planning] In this industry it is widely understood that "maintain," is not simply to establish the plan. The intent of the EOP SDT is for BAs and TOPs to keep its Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies contemporary and for the Emergency Plan to stay contemporary.
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	Retired under Criteria B6 and B7 of P81 guidelines.	**<u>Retirements</u>** **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		**Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and • Transaction arrangements are a commercial practice. **Requirement R6.3** • Meets Criterion B7 of Paragraph 81; and • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]* To have a TOP or BA contact other TOPs and BAs takes them away from the Emergency at hand, plus they do not have a wide-area view. The RC can give an indication

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		of impact and make high-level determinations. The RC has the wide-area overview and can quickly determine impacts of neighboring TOPs, BAs and RCs. The RC is to make contact within 30 minutes of notification. From there, IRO-005, IRO-006 and IRO-007 would address the specific actions to be taken.
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	EOP-002-3.1, R5 maps to BAL-003-1, R1, R2, R3, and R4.	**BAL-003-1, R1** R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. **BAL-003-1, R2**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. **BAL-003-1, R3** R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: (1.1) Less than zero at all times, and (1.2) Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 [Hertz] Hz by more than +/- 0.036 Hz. **BAL-003-1, R4**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority area, to be equivalent to either: • the sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • the Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' areas.
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.4. Requesting emergency assistance from other Balancing Authorities. **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.		2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R6** R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange		request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Transaction on the system from Priority 6 to Priority 7.		
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.	Translated to EOP-011-1, Attachment 1.	**Attachment 1EEA 2 – Load management procedures in effect** • An energy deficient BA is still able to maintain minimum Contingency Reserve requirements. Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA. The previous language in EOP-002-3.1, EEA 2 used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	Translated to EOP-011-1, Emergency Operations. Rehearing of FERC Order No. 763, Paragraph 11: *"Accordingly, we grant clarification that <u>Order No. 763 did not preclude some degree of overlap between automatic and manual load</u>*	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	<u>shedding programs,</u> provided there is sufficient non-overlapping load available for manual shedding to achieve the reliability objective of EOP-003-2.”	1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. Rehearing of FERC Order No. 763, Paragraph 11: *"Accordingly, we grant clarification that <u>Order No. 763 did not preclude some degree of overlap between automatic and manual load shedding programs,</u> provided there is sufficient non-overlapping load available for manual shedding to achieve the reliability objective of EOP-003-2."*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Exhibit K

Standard Drafting Team Roster for NERC Standards Development Project 2010-14.1

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves Standards Drafting Team Roster

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