Exhibit A

Proposed Reliability Standard BAL-005-1

BAL-005-1 Clean Version

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstratea common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of the	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.

			inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	**Operations Assessment**	**Medium**	**The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.**	**The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.**	**The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.**	**The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.**
R6.	**Same-day Operations**	**Medium**	**N/A**	**N/A**	**N/A**	**The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.**
R7.	**Operations Planning**	**Medium**	**N/A**	**N/A**	**N/A**	**The Balancing Authority failed to use a common source for Tie-Lines, Pseudo-ties and Dynamic**

						Schedules with its Adjacent Balancing Authorities **Or** **The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition

0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	
1	February 11, 2016	Adopted by NERC Board of Trustees	Complete re-write of standard

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board approval, the text from the rationale boxes will be moved to this section.

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan-rate values used in Reporting ACE.

BAL-005-1 Redline Version

A. Introduction

1. **Title:** ~~**Automatic Generation**~~ Balancing Authority Control

2. **Number:** BAL-005-~~0.2b~~1

3. **Purpose:** This standard establishes requirements for ~~Balancing Authority Automatic Generation Control (AGC)~~acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE~~) and to routinely deploy the Regulating Reserve.~~). The standard also ~~ensures that all facilities~~specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and ~~load electrically synchronized to~~for providing the ~~Interconnection are included within~~ information to the ~~metered boundary of a Balancing Area so that balancing of resources and demand can be achieved~~System Operator.

4. **Applicability:**

~~4.1. Balancing Authorities~~

~~4.2. Generator Operators~~

~~4.3. Transmission Operators~~

~~4.4.~~**4.1.** ~~**Load Serving**~~**Functional Entities:**

4.1.1. Balancing Authority

~~5.~~ **Effective Date:** ~~May 13, 2009~~ See Implementation Plan for BAL-005-1

~~B.~~ Requirements

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

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

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

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

~~R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retirement approved by FERC effective January 21, 2014.)~~

R1. Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

~~**R3.**~~ A Balancing Authority ~~providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.~~

~~**R4.** A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it~~ that is unable to ~~provide the service, as well as any Intermediate Balancing Authorities.~~

~~**R5.** A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.~~calculate Reporting ACE for more than 30-consecutive

~~**R6.**~~**R2.** ~~The Balancing~~ ~~Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30~~ minutes ~~it~~ shall notify its Reliability Coordinator~~.~~ within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

~~**R7.**~~ The Balancing Authority shall ~~operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become~~

~~inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.~~

~~**R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.~~

~~**R8.1.**~~**M3.** ~~Each Balancing Authority shall provide redundant and independent~~ have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment ~~that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide~~used for the calculation of Reporting ACE had a minimum availability of 99.95~~%.~~% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

~~**R9.**~~ The Balancing Authority shall ~~include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.~~

~~**R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled~~have dated evidence such as ~~internal generation or load.~~

~~**R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.~~

~~**R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities,~~voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstrate a common source for the components used in the ~~Scheduled Interchange values to calculate ACE.~~

~~**R12.**~~**M7.** ~~Each Balancing Authority shall include all Tie Line flows~~calculation of Reporting ACE with its Adjacent Balancing Authority ~~Areas in the ACE calculation~~.

~~**R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.~~

~~**R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.~~

~~**R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.~~

~~**R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error~~ ~~(I_{ME})~~ ~~term of the ACE equation to compensate for any equipment error until repairs can be made.~~

~~**R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.~~

~~**R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.~~

~~**R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.~~

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

~~Device~~	~~Accuracy~~
~~Digital frequency transducer~~	~~≤ 0.001 Hz~~
~~MW, MVAR, and voltage transducer~~	~~≤ 0.25 % of full scale~~
~~Remote terminal unit~~	~~≤ 0.25 % of full scale~~
~~Potential transformer~~	~~≤ 0.30 % of full scale~~
~~Current transformer~~	~~≤ 0.50 % of full scale~~

~~C. Measures~~

~~Not specified.~~

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

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

~~1.1.1.~~ ~~Within one week upon request, Balancing Authorities shall provide~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional ~~Reliability Organization CPS source data~~ Entity in ~~daily CSV files~~their respective roles of monitoring and enforcing compliance with ~~time stamped one minute averages of: 1) ACE and 2) Frequency Error.~~

~~1.1.2.~~ ~~Within one week upon request, Balancing Authorities shall provide~~ the NERC ~~or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance~~Reliability Standards.

~~1.2. Compliance Monitoring Period and Reset Timeframe~~

~~Not specified.~~

~~1.3.~~1.2. ~~Data~~Evidence Retention

~~1.3.1.~~ ~~Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.~~

~~1.3.2.~~ ~~Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.~~

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

~~Not specified.~~

~~**Levels**~~None

~~2.~~ Table of ~~Non-~~Compliance Elements

~~Not specified.~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of the	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.

			inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R7.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a common source for Tie-Lines, Pseudo-ties and Dynamic

						Schedules with its Adjacent Balancing Authorities Or The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.

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

None.

E. Interpretations

None~~None identified~~.

F. Associated Documents

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

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
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0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition

0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	
1	February 11, 2016	Adopted by NERC Board of Trustees	Complete re-write of standard

~~Appendix 1~~

~~Effective Date: August 27, 2008 (U.S.)~~

~~Interpretation of BAL-005-0 Automatic Generation Control, R17~~

~~Request for Clarification received from PGE on July 31, 2007~~

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

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

~~**BAL-005-0**~~

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

~~**Device**~~	~~**Accuracy**~~
~~Digital frequency transducer~~	~~≤ 0.001 Hz~~
~~MW, MVAR, and voltage transducer~~	~~≤ 0.25% of full scale~~
~~Remote terminal unit~~	~~≤ 0.25% of full scale~~
~~Potential transformer~~	~~≤ 0.30% of full scale~~
~~Current transformer~~	~~≤ 0.50% of full scale~~

~~**Existing Interpretation Approved by Board of Trustees May 2, 2007**~~

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

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

~~**Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007**~~

~~As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.~~

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

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board approval, the text from the rationale boxes will be moved to this section.

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan-rate values used in Reporting ACE.

Exhibit B

Proposed Reliability Standard FAC-001-3

FAC-001-3 Clean Version

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3.
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	
3	February 11, 2016	Adopted by the Board of Trustees	Moved BAL-005-0.2b Requirement R1 into FAC-001-3 Requirements R3 and R4

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board approval, the text from the rationale boxes will be moved to this section.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

FAC-001-3 Redline Version

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-~~2~~3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. ~~**Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is one year after the date that this 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 one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~**Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The ~~Transmission Owner and~~ applicable ~~Generator Owner~~Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	~~N/A~~The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner ~~addressed either~~failed to address two parts of Requirement R3~~,~~ Part 3.1 ~~or~~through Part 3.~~2 in its Facility interconnection requirements, but did not address both.~~3.	The Transmission Owner ~~addressed neither~~failed to address Requirement R3~~,~~ Part 3.1 ~~nor~~through Part 3.~~2 in its Facility interconnection requirements. ~~3.
R4	Long-term Planning	Lower	N/A	~~N/A~~The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The ~~applicable~~ Generator Owner ~~addressed either~~failed to address two parts of Requirement R4~~,~~ Part 4.1 ~~or~~through Part 4.~~2 in its Facility interconnection requirements, but did not address both.~~3.	The ~~applicable~~ Generator Owner ~~addressed neither~~failed to address Requirement R4~~,~~ Part 4.1 ~~nor~~through Part 4.~~2 in its Facility interconnection requirements. ~~3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
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2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	
3	February 11, 2016	Adopted by the Board of Trustees	Moved BAL-005-0.2b Requirement R1 into FAC-001-3 Requirements R3 and R4

~~Application Guidelines~~

Supplemental Material

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

~~Application Guidelines~~

Supplemental Material

~~Application Guidelines~~

Supplemental Material

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon Board approval, the text from the rationale boxes will be moved to this section.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Exhibit C

Redline of Reliability Standard BAL-006-2

Introduction

1. **Title:** ~~**Inadvertent Interchange**~~

2. **Number:** ~~BAL-006-2~~

3. **Purpose:**

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

4. **Applicability:**

~~**4.1.** Balancing Authorities.~~

5. **Effective Date:**

B. Requirements

~~**R1.** Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)~~

~~**R2.** Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)~~

~~**R3.** Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)~~

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

~~**R4.1.** Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)~~

~~The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)~~

~~The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)~~

~~**R4.2.** Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)~~

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

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

C. Measures

~~None specified.~~

D. Compliance

1. Compliance Monitoring Process

~~**1.1.** Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).~~

~~**1.2.** Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.~~

~~**1.3.** Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.~~

~~**1.4.** Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.~~

~~**1.5.** Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.~~

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~N/A~~	~~N/A~~	~~N/A~~	~~Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.~~
R2.	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account.~~ ~~OR~~ ~~Failed to take into account interchange served by jointly owned generators.~~	~~The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account.~~ ~~AND~~ ~~Failed to take into account interchange served by jointly owned generators.~~
R3.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.~~
R4.	~~The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.~~	~~The Balancing Authority failed to compute Inadvertent Interchange.~~	~~The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.~~	~~N/A~~
R4.1.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged~~

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Schedule.~~ ~~AND~~ ~~The hourly integrated megawatt-hour values of Net Actual Interchange.~~
R4.1.1.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.~~
R4.1.2.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.~~
R4.2.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.~~
R4.3.	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent~~

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Interchange.~~
R5.	~~Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.~~	~~Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.~~	~~N/A~~	~~N/A~~

E. Regional Differences

~~1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.~~

Version History

Version	Date	Action	Change Tracking
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~August 8, 2005~~	~~Removed "Proposed" from Effective Date~~	~~Errata~~
~~1~~	~~April 6, 2006~~	~~Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.~~	~~Errata~~
~~2~~	~~November 5, 2009~~	~~Added approved VRFs and VSLs to document.~~ ~~Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver (Project 2009-18).~~	~~Revision~~
~~2~~	~~November 5, 2009~~	~~Approved by the Board of Trustees~~	
~~2~~	~~January 6, 2011~~	~~Approved by FERC~~	

Exhibit D

Implementation Plan for Proposed BAL-005-1

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls
Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control
- BAL-006-2 – Inadvertent Interchange - Requirement R3

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(\mathbf{1}-\boldsymbol{Y})*\boldsymbol{H}}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{\boldsymbol{hourly}}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 Requirement R3 will be retired concurrently with the effective date for BAL-005-1 . Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

after the effective date of the applicable governmental authorities order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of Automatic Generation Control, Pseudo Tie and Balancing Authority shall be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

Exhibit E

Implementation Plan for FAC-001-3

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Reliability Standard FAC-001-3

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- FAC-001-3 – Facility Interconnection Requirements

Requested Retirement

- FAC-001-2 – Facility Interconnection Requirements

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

Background

Reliability Standard FAC-001-3 addresses Facility Interconnection Requirements, which ensure the avoidance of adverse impacts on the reliability of the Bulk Electric System by requiring Transmission Owners and applicable Generator Owners to document and make Facility interconnection requirements available so that entities seeking to interconnect will have necessary information. Reliability Standard FAC-001-3 and associated Implementation Plan was developed in conjunction with BAL-005-1 (Balancing Authority Controls) to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented concurrently with BAL-005-1, as reflected in the "Prerequisite Approvals" section above.

Effective Dates

FAC-001-3 shall become effective on the effective date of BAL-005-1.

Retirements

FAC-001-2 (Facility Interconnection Requirements) shall be retired immediately prior to the Effective Date of FAC-001-3 (Facility Interconnection Requirements) in the particular jurisdiction in which the revised standard is becoming effective.

Exhibit F

Implementation Plan for Retirement of BAL-006-2

Implementation Plan

Reliability Standard BAL-006-2

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2 will be retired concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2 shall be retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

Exhibit G

Analysis of Violation Risk Factors and Violation Severity Levels for BAL-005-1

NERC
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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

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-005-1, Balancing Authority Control. 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-005-1:
There are seven requirements in BAL-005-1. All of the requirements were assigned a "Medium" VRF.

VRF for BAL-005-1, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R3 and Requirement R5. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R8.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is identical to the current enforceable BAL-005-0.2b Standard Requirement R8 which has 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 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-005-1, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a “Medium” VRF. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R6.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is identical to the current enforceable BAL-005-0.2b standard Requirement R6 which has 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 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-005-1, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a “Medium” VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R8.1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has 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 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-005-1, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has 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 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-005-1, Requirement R5:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R3 which has a 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 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-005-1, Requirement R6:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R7 which has a 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 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-005-1, Requirement R7:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has a Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has an approved Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher 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 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-005-1 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-005-1 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. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. The proposed VSL language does not include ambiguous terms. The VSL is similar to the current approved VSL for BAL-005-0.2b Requirement R8.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for BAL-005-1 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 levels of noncompliance performance.	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-005-1 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.	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 an entity is non-compliant with the requirement.	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.

VSLs for BAL-005-1 Requirement R4:

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
R4.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the information was provided.	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.

VSLs for BAL-005-1 Requirement R5:

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
R5.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	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 an entity is non-compliant with the requirement.	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.

VSLs for BAL-005-1 Requirement R6:

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
R6.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	This requirement is new. As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the entity implemented an Operating Process to identify and mitigate errors.	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.

VSLs for BAL-005-1 Requirement R7:

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
R7.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. 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. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on single violations and not a cumulative violation methodology.

Exhibit H

Analysis of Violation Risk Factors and Violation Severity Levels for FAC-001-3

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Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in FAC-001-3, Facility Interconnection Requirements. 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 FAC-001-3:

There are four requirements in FAC-001-3. All of the requirements were assigned a "Lower" VRF.

VRF for FAC-001-3, Requirement R1:

There were no changes made to requirement R1. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a "Lower" VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R3.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R3 which has an approved Lower 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 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 FAC-001-3, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a "Lower" VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R4.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R4 which has an approved Lower 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 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 FAC-001-3 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 FAC-001-3 Requirement R1:

There were no changes made to requirement R1. The current FERC approved VSLs are proposed to remain in effect.

VSLs for FAC-001-3 Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VSLs for FAC-001-3 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.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	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 number of parts the entity failed to address.	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.

VSLs for FAC-001-3 Requirement R4:

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
R4.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the number of parts the entity failed to address.	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 I

BAL-005-1 Mapping Document

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Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	Requirement R1 Part R1.1 and Part R1.2 have been moved into FAC-001-2 Requirement R3 and R4. Requirement R1 Part R1.3 is being retired.	Requirements R1 Parts R1.1 and R1.2 do not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system. Requirement R1 Part 1.3 is being retired in conjunction with the Risk-based Registration initiative de-certifying the LSE function.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R2	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R2.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R1 and Part 8.1 was moved into Requirement R3	The body of this requirement has been moved to Requirement R1 and Part 8.1 has been moved into Requirement R3.
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R7 ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R7	This requirement has been moved to Requirement R7.
BAL-005-0.2b R13	Moved to Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R7. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R4 and Requirement R7	This requirement has been moved into Requirement R4 and Requirement R7.
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality. In addition, proposed R3 requires a performance level that the Balancing Authority Area must meet. The standard does not tell the BAA how to meet it.
BAL-005-0.2b R16	Moved to Requirement R4	This requirement has been moved into Requirement R4.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R3)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R3.

Exhibit J

FAC-001-3 Mappnig Document

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Project 2010-14.2.1 Mapping Document
Transition of FAC-001-2 to FAC-001-3

Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R3 Part 3.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R4 Part 4.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.

Exhibit K

BAL-006-2 Mapping Document

Project 2010-14.2.1 Mapping Document

Transition of BAL-006-2

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R2	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R3	Moved to BAL-005-1 Requirement R7	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R5	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**

Exhibit L

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Introduction:

Tie Line Bias[1] (TLB) control has been used as the preferred control method in North America for 75 years. In the early 1950's the term Area Control Error (ACE) was developed for the specific implementation of coordinated Tie Line Bias control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE[2] in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary; reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the Bulk Electric System.

The following definitions are included in the NERC Glossary:

Definition:
Actual Frequency **F_A** **5/11/2015**
The Interconnection frequency measured in Hertz (Hz).

Definition:
Actual Net Interchange **NI_A** **5/11/2015**
The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, with all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange.

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[1] Capitalized terms hold the same definition as in the NERC glossary throughout this document.

[2] The CPS1 measure was among the first of the results based measures developed by NERC. It defined not how to perform control, but instead defined the target control results that were to be achieved, and a method to measure whether or not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, Area Control Error (ACE) has been used to describe many terms involved in TLB Control. Within a BAA's Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions in order to smooth the control signals; or, there may be additional "feed-forward" terms added to ACE in anticipation of future changes (e.g. anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting to improve the quality of control for the specific characteristics of that particular BAA.

Some auditors have raised compliance issue related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in BAL-001. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Definition:

Automatic Time Error Correction **I_{ATEC}** **5/11/2015**

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 (PII) to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

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

The absolute value of **I_{ATEC}** shall not exceed **L_{max}** **.**

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

- **L_{max}** is the maximum value allowed for **I_{ATEC}** set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- **L_{10}** $= 1.65 * \mathcal{E}_{10}\sqrt{(-10\mathrm{B_i})(-10\mathrm{B_S})}$.
- **$\mathcal{E}_{10}$** 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, $\mathcal{E}_{10}$, is the same for every Balancing Authority Area within an Interconnection.
- **Y** = B_i / B_S.
- **H** = Number of hours used to payback primary Inadvertent Interchange energy. The value of H is set to 3.
- **B_i** = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- **B_S** = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (**PII_{hourly}**) is (1-Y) ∗ (II_{actual} – B_i ∗ 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

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

Definition:

Frequency Bias Setting **B** **4/1/2015**

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority Area's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Definition:
Interchange Meter Error **I_{ME}** **5/11/2015**
A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Definition:
Reporting ACE **RACE** **5/11/2015**
The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Definition:
Scheduled Frequency **F_S** **3/16/2007**
60.0 Hz, except during a manual Time Error Correction.

Definition:
Scheduled Net Interchange **NI_S** **5/11/2015**
The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Structure:

The effective use of Reporting ACE within a TLB control program should address the following components:

(I) Management Roles and Expectations
(II) Information Technology Roles
(III) System Operator Roles
(IV) Manual Source Data Entry
(V) Automatically Collected Source Data
(VI) Uses of Reporting ACE
(VII) Historic Data Management
(VIII) Special Conditions and Calculations

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the Tie Line Bias control program.

Each responsible entity should evaluate all of its uses for Reporting ACE in its operations and its reliability measurement. Reporting ACE is one of the most important single measurements available to indicate the current state of the Responsible Entity's contribution to interconnection reliability.[3] Reporting ACE is also used as an integral part of the measurements used in BAL-001 and BAL-002. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in BAL-003 and BAL-005.

I. Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Tie Line Bias control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

a. Set expectations for safety, reliability, and operational performance.

[3] When configured with a Frequency Bias Setting equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match its actual interchange, less the impact from its current Frequency Response offset, to its scheduled interchange.

b. Assure that a TLB control program exists for each responsible entity and is current.
c. Provide annual training on the TLB control program and its purpose and requirements.
d. Ensure the proper expectation of TLB control program performance.
e. Share insights across industry associations.

II. Information Technology (IT) Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE and source information are always current and correct.
c. Implement the TLB control program in Real-time.
d. Ensure that the EMS supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.
e. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.
f. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the following calculations and equations:

1) Actual Net Interchange[4] (NI_A):

All BAAs involved account for the power exchange and associated transmission losses as actual interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout all of their energy accounting processes.

i. Calculate for each scan.[5]
ii. Integrated hourly average calculated for each hour as an integration of the scan rate values.

[4] By definition "Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.

[5] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

2) Scheduled Net Interchange[6] (NI_S):
   i. Calculate for each scan.
   ii. Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

   Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout all of their energy accounting processes.

3) Frequency Error ($\Delta F = (F_A - F_S)$):
   i. Calculate for each scan.
   ii. Calculate clock-minute average from valid samples available within each clock-minute[7] where at least half of the scan-rate samples are valid.

4) Frequency Trigger Limit – Low (FTL_{Low})[8]:

   Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

5) Frequency Trigger Limit – High (FTL_{High})[9]:

   Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

6) Accumulated primary Inadvertent Interchange (PII): Calculated each hour for WECC BAAs only.

$$\boldsymbol{PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}}$$

7) Automatic Time Error Correction (IATEC): Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

   $\boldsymbol{I_{\mathrm{ATEC}} = \frac{PII_{accum}^{on/off\ peak}}{(1-Y)*H}}$ when operating in ATEC mode.

   The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$ **.**

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

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6 By definition "Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

7 Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

8 This variable could be entered manually as long as it is changed every time a manual time error correction is started or stopped. If manual time error correction is eliminated, it could become a constant and entered manually.

8) Reporting ACE:
   i. Calculate for each scan.
   ii. Calculated average for each clock-minute for BAAs using a fixed Frequency Bias Setting when at least half of the values are valid.[9]

9) Compliance Factor[10]:
   i. Calculate for each scan where both Reporting ACE and Frequency Error are valid.
   ii. Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[11]

10) Clock-hour compliance factor[8]:

    Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

11) Month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid clock-minute compliance factors in the month.

12) 12-month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

13) CPS1 compliance factor:

    Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the $Epsilon_1$ value for the Interconnection.

14) CPS1:
   i. Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.
   ii. Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.
   iii. Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2

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[9] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid.

[10] Used for CPS1.

[11] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid and the average clock-minute Frequency Error is valid.

and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

iv. Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

v. Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

15) Balancing Authority ACE Limit - Low ($BAAL_{Low}$):

i. Calculate the scan rate Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

16) Balancing Authority ACE Limit - High ($BAAL_{High}$):

i. Calculate the scan rate Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

17) Balancing Authority ACE Limit - Low Compliance:

i. Alarm $BAAL_{Low}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$.

ii. Indicate $BAAL_{Low}$ non-compliance for each period where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$ for more than 30-consecutive clock-minutes.

18) Balancing Authority ACE Limit - High Compliance:

i. Alarm $BAAL_{High}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$.

ii. Indicate $BAAL_{High}$ non-compliance for each period where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$ for more than 30 consecutive clock minutes.

g. Ensure that the EMS supports the retention of all historic data including data quality information required to be retained to support continuing operations and audit requirements.

h. Ensure that the EMS supports and manages the presentation of all information required to be available to the System Operator for real-time operations, operations staff for evaluation of operations, and auditors for compliance confirmation.

i. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.

III. System Operator and Operations Staff Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE information is always current and correct.
c. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.
d. Implement the TLB control program in Real-time.

IV. Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[12], by the Responsible Entity's Energy Management System (EMS), and may be partially based on source data manually entered into that system. The following source data may be entered:

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent Balancing Authority Areas may not be available from an automatic collection source, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent Balancing Authority Areas entering the manual data. If the actual flow estimates are the same for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

NI_S (Scheduled Net Interchange): The power transfer schedules, including the schedule ramps where applicable, are processed by the EMS. If scheduled flow estimates are equal and have opposite signs for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The Frequency Bias Setting, or minimum required value, for the Balancing Authority Area is specified by calculations performed as part of compliance with BAL-003-1 - Frequency Response and Frequency Bias Setting;

R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area 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

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[12] BAL-005-1 Balancing Authority Control - R2. The Balancing Authority shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE.

(ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.[13]

10 is the factor (10 0.1Hz/Hz) that converts the Frequency Bias Setting units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor as specified in BAL-004-0.[14] It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all times.

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for **I_{ATEC}** set by each BA between $0.2*|B|$ and L_{10}, $0.2*|B| \leq L_{max} \leq L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is normally set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum Frequency Bias Settings for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the interconnection.

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[13] As a note of interest, the new procedures put forth with BAL-003-1 will result in the reduction of minimum Frequency Bias Setting values on the multiple BA interconnections to bring them closer to the natural measured Frequency Response of the interconnection. The rule requiring a minimum Frequency Bias Setting of 1% of peak load in the NERC Standards dates back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response which was 2% of peak load at that time. The 1% figure is now more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid.

[14] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

V. Automatically Collected Source Data

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds[15], by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the System Operators. This data quality information is presented to the System Operator to have situational awareness with respect to the quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as CPS1, BAAL, DCS, and frequency response obligation (FRM).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[16,17,18,19] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the System Operator to support situational awareness.[20] The EMS sums the individual flow values on all tie lines and pseudo ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry element is passed to the result of all calculations using that element.

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent Balancing Authority Area, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent Balancing Authority Area for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005[21] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

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[15] BAL-005-1 Balancing Authority Control – "R2. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[16] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS. See the attached document titled "Anti-aliasing Filtering."

[17] It is acceptable to collect tie-line flow data from RTUs that use report by exception as long as those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[18] The six-second scan rate not only assures that data collected is close to Real-time, it also limits the latency (time skew) associated with the data collection.

[19] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[20] Indications of suspect data are usually indicated with color changes and/or alarms.

[21] BAL-005 – Automatic Generation Control specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the Digital Frequency Transducer.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange. (Block schedules are not used for this calculation.)

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

VI. Uses of Reporting ACE

a. Reporting ACE is currently used to measure secondary frequency control within TLB control on all of the Interconnections.[22] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing Standards. The following standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

   i. BAL-001-1 – Real Power Balancing Control Performance and BAL-001-2 – Real Power Balancing Control Performance.

   ii. BAL-002-1 – Disturbance Control Performance and BAL-002-2 – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved).

   iii. BAL-005-0.2b – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved).

   iv. BAL-006-2 Inadvertent Interchange.

b. The industry may also consider the use of Reporting ACE in the future to evaluate the rules associated with transmission loading.

VII. Historic Data Management

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and "TLB control program".

VIII. Special Conditions and Calculations

IX. **I_{ME} (Interchange Meter Error):** BAL-005-1 R6 requires, "Each Balancing Authority Area that is within a multiple Balancing Authority Area interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE." Ideally, errors identified should be corrected immediately, but this is not always possible. The **I_{ME}** term, normally zero, can be used by the System Operator or operations staff to add a correction term in the Reporting ACE calculation correcting errors affecting the scan-rate accuracy of data, thus mitigating the error in the calculation of Reporting ACE until telemetry errors can be corrected.

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[22] On single BAA Interconnections, the ACE Equation reduces to a single term, **$-10B\ (F_A - F_S)$**, because there are no tie lines or schedules to include in the first term, **$(NI_A - NI_S)$**, and there is no **I_{ME}** term to correct for tie line or dynamic schedule measurement errors in the first term.

The calculation of the $\mathbf{I_{ME}}$ is the one of the results of this required Operating Process. It compensates for data or equipment errors affecting components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. The process used for including adjustments in the $\mathbf{I_{ME}}$ term should be based on good quality control methods.[23]

The goal associated with the use of the $\mathbf{I_{ME}}$ is to encourage the scan-rate values of actual and scheduled interchange between Adjacent Balancing Authorities to be equal in magnitude and have opposite signs.[24] Unfortunately, these values cannot be directly compared with each other because of differences between scan time and differences between scan-rates between BAAs. When initially configured, all BAs used “Digital to Analog” converters and “Analog to Digital” converters to transmit tie-line flows and accumulated MWh values from the common metering point required in the standards to the BA’s EMS. These “D to A” and “A to D” converters are subject to error and require frequent calibration, and although, many have been replaced by digital telemetry, they still exist and require oversight. Any difference between the scan-rate values agreed to by Adjacent BAAs that is not included in the error mitigation process will be passed to the interconnection for management and will not be included in the performance measures such as CPS1, BAAL and FRM.

Energy Management Systems are capable of integrating the scan-rate values used for the calculation of Reporting ACE and providing those integrated values for comparison to the accumulated megawatt-hour values for the same meters. If the integrated scan rate values are close to the accumulated megawatt-hour values, then one can conclude that the scan-rate values accurately represent the accumulated values. The final step in this process includes a comparison and agreement on the accumulated megawatt-hour values between the Adjacent BAAs sharing the measurement. If the differences between accumulated values between Adjacent BAAs is not included in this process, any adjustments to the accumulated values made by a BAA to achieve agreement with an adjacent BAA will be excluded from the analysis and will not be mitigated. This information used in conjunction with a similar analysis of the scan rate values for the same measurement by the Adjacent Balancing Authority Area including analysis of any differences between the accumulated values and the agreed to accumulated values. This total process provides reasonable assurance that the scan-rate tie line flows or the dynamic schedules used by Adjacent BAAs are consistent with one another confining control problems within the boundaries of the Adjacent BAAs.

[23] Adjustments to the $\mathbf{I_{ME}}$ term should follow good quality control methods and exclude tampering as demonstrated by the Deming’s Funnel Experiment, http://blog.newsystemsthinking.com/w-edwards-deming-and-the-funnel-experiment/ .

[24] As long as the scan-rate tie line flows and scheduled flows match for Adjacent Balancing Authority Areas, any problems with the measurement of balancing on the interconnection will be confined to within the boundaries of those Adjacent Balancing Authority Areas. Any mismatch will pass the difference to the interconnection and will result in frequency control error that will to be excluded from performance measurement and managed by all BAAs through the frequency bias terms of their Reporting ACE.

These error correction adjustments can be used to correct errors in the **NI_A** or **NI_S**[25] terms for Reporting ACE and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the **I_{ME}** term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-1.

a. **Use of Source-Sink Pairs for Asynchronous DC Tie Lines to Another Interconnection:** One of the primary rules for insuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie lines, pseudo ties, interchange schedules and Dynamic Schedules to Adjacent Balancing Authority Areas and only Adjacent Balancing Authority Areas on the same Interconnection, and requiring the exclusion of all asynchronous DC tie lines and associated scheduled interchange with Balancing Authority Areas on a different Interconnection from Reporting ACE. Following this simple rule insures that all loads, losses and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie line bias control program. One terminal of an asynchronous DC tie line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie line will exclude the asynchronous tie line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

[25] Errors in the **NI_S** would only occur and only support correction in cases where there is a measurement error associated with a Dynamic Schedule.

Exhibit N

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standards BAL-005-1, BAL-006-3, and FAC-001-3 are 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 if the NERC Standards Process 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 O**.

II. Standard Development History

A. Periodic Review Recommendations

A review team was assembled in the fall of 2013 to conduct a periodic review of Balancing Authority Reliability-based Controls Reliability Standards BAL-005-0-2b and BAL-006-2. The Balancing Authority Reliability-based Controls Periodic Review Team ("BARC 2 PRT") proposed several recommendations, and based upon consideration of comments, the BARC 2 PRT submitted the recommendations to the NERC Standards Committee ("SC") on February 21, 2014 for review.

B. Standard Authorization Request Development

After submitting its recommendations to revise BAL-005-0-2b and BAL-006-2, the BARC 2 PRT submitted a Standard Authorization Request ("SAR") and associated proposed Reliability Standards and associated documents implementing the BARC 2

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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.

PRT findings to the SC. The SAR and proposed Reliability Standards were originally posted for 30-day public comment period from July 16, 2014 through August 14, 2014. There were 19 sets of responses, including comments from approximately 95 different individuals from approximately 75 companies representing 9 of the 10 Industry segments.[3]

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

Proposed Reliability Standards BAL-005-1, BAL-006-3, and FAC-001-3 were posted for a 45-day formal comment period from July 30, 2015 through September 14, 2015, with an initial ballot held from September 4, 2015 through September 14, 2015. Several documents were posted for guidance with the first draft, including the standard documents, implementation plans, Mapping Documents for BAL-005-1, BAL-006-3, FAC-001-3, and a White Paper called "Calculating and Using Reporting ACE in a Tie Line Bias Control Program." The initial ballot reached quorum at 83.81% of the ballot pool with 55.97% approval. The Non-Binding Poll reached quorum at 83.64% and the standard and associated documents received support from 56.90% of the voters. There were 46 sets of responses, including comments from approximately 131 different individuals and approximately 87 companies, representing 9 of the 10 industry segments.[4]

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[3] NERC, *Consideration of Comments*, Project 2010-14.2 Periodic Review of BAL Standards, (July 2015), *available at* http://www.nerc.com/pa/Stand/Project%2020101421%20Phase%202%20DL/Consideration_of_Comments_2010-14_2_Periodic_Review_BAL_20150715.pdf.

[4] NERC, *Consideration of Comments*, Project 2010-14.2.1, (Nov. 10, 2015), *available at* http://www.nerc.com/pa/Stand/Project%2020101421%20Phase%202%20DL/2010-14_2_1_Phase_2_of_BARC_BAL-005_and_BAL-006_Consideration_of_Comments_11102015.pdf

D. Survey Period for White Paper and Retirement of BAL-006-2

On September 16, 2015, the Inadvertent Interchange Whitepaper, explaining inadvertent interchange calculations used by industry, as well as a survey concerning the disposition of BAL-006, were posted for industry comment. According to the BARC 2 SDT, the Independent Expert Review Report and BARC 2 PRT reviewing BAL-005-0.2b and BAL-006-2, and several industry participants had previously indicated that much of currently-effective Reliability Standard BAL-006-2 is an energy accounting standard and not a NERC Reliability Standard. Thus, the survey was intended to gauge how the industry intended to accommodate the need for energy accounting. There were 14 sets of responses, including comments from approximately 43 different individuals and approximately 33 different companies, representing 6 of the 10 Industry Segments.[5]

E. Second Posting - Comment Period, Additional Ballots and Non-Binding Polls

Proposed Reliability Standards BAL-005-1, BAL-006-3, and FAC-001-3 were posted for a 45-day formal comment period from November 10, 2015 through January 11, 2016, with an additional parallel ballot held from December 31, 2015 through January 11, 2016. The additional ballot received for BAL-005-1 reached quorum at 84.13% of the ballot pool, and the standard and associated documents received support from 70.64% of the voters. The additional ballot for BAL-006-2 reached quorum at 84.44% of the ballot pool, and the standard and associated documents received support from 94.30% of the voters. The additional ballot received for FAC-001-3 reached quorum at 83.17% of the ballot pool, and the standard and associated documents received support from 75.54% of the voters. The related Non-Binding Poll for BAL-005-1 reached quorum 82.53% of the

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5 NERC, *Consideration of Comments*, Project 2010-14.2.1, (2015), *available at* http://www.nerc.com/pa/Stand/Project%2020101421%20Phase%202%20DL/2010-14%202%201_Phase_2_BAL-006-2_Survey_Consideration_of_Comments_11102015.pdf.

ballot pool, and the standard and associated documents received support from 74.38% of the voters. The related Non-Binding Poll for FAC-001-3 reached quorum 82.53% of the ballot pool, and the standard and associated documents received support from 75.44% of the voters. During the comment period, there were 43 sets of responses, including comments from approximately 117 different individuals and approximately 84 companies, representing 8 of the 10 industry segments.[6]

F. Final Ballot

Proposed Reliability Standards BAL-005-1, BAL-006-3, and FAC-001-3 were posted for a 10-final ballot period from January 29, 2016 through February 8, 2016. The ballot for the proposed Reliability Standard BAL-005-1 and associated documents reached quorum at 86.35% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 72.06% of the voters. The ballot for proposed retirement of Reliability Standard BAL-006-2 reached quorum at 86.98% of the ballot pool, and the retirement received sufficient affirmative votes for approval, receiving support from 94.61% of the voters. The ballot for the proposed Reliability Standard FAC-001-3 and associated documents reached quorum at 86.67% of the ballot pool, and the standard received sufficient affirmative votes for approval, receiving support from 80.15% of the voters.[7]

G. Board of Trustees Adoption

Proposed Reliability Standards BAL-005-1, BAL-006-3, FAC-001-3, and all associated documents were adopted by the NERC Board of Trustees on February 11, 2016.

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6 NERC, *Consideration of Comments*, Project 2010-14.2.1, (Jan. 28, 2016), *available at* http://www.nerc.com/pa/Stand/Project%2020101421%20Phase%202%20DL/2010-14.2.1_BAL-005-1_BAL-006-2_FAC-001-3_C_of_C_01282016.pdf.

7 NERC, *Standards Announcement*, Project 2010-14.2.1 (Feb. 2016), *available at* http://www.nerc.com/pa/Stand/Project%2020101421%20Phase%202%20DL/2010-14.2.1_BAL-005_006_FAC-001_FB_Results_Word_Announce_02162016.pdf.

Complete Record of Development History

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001

Related Files | 2007-05 - Balancing Authority Controls | 2007-18 - Reliability-based Control | 2010-14.2 - Periodic Review of BAL Standards

Status

Final ballots for **BAL-005-1 – Balancing Authority Control, FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange** concluded **8 p.m. Eastern, Monday, February 8, 2016.** The voting results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0_2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn.

As a result of that examination, the BARC 2 PRT recommended to REVISE BAL-005-0_2b and BAL-006-2.

The NERC Standards Committee appointed ten industry subject matter experts to serve on the BARC 2 standard drafting team (BARC 2 SDT) in the fall of 2014.

Standard(s) Affected: BAL-005-0.2b - Automatic Generation Control, BAL-006-2 - Inadvertent Interchange, FAC-001-1 - Facility Connection Requirements

Purpose/Industry Need

The objective of BAL-005 is to establish requirements for acquiring necessary data for the Balancing Authority to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. The current objective of BAL-006 is to define a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations. As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft BAL-005-1 Clean **(71)** | Redline to Last Posted **(72)** Redline to Last Approved **(73)** FAC-001-3 Clean **(74)** | Redline to Last Posted **(75)** Redline to Last Approved **(76)** Implementation Plans BAL-005-1 Clean **(77)** | Redline to Last Posted **(78)** BAL-006-2 Clean **(79)** | Redline to Last Posted **(80)** FAC-001-3 **(81)** White Paper **(82)**	Final Ballots Info **(83)** Vote	01/29/16 - 02/08/16	Summary **(84)** Ballot Results BAL-005-1 **(85)** BAL-006-2 **(86)** FAC-001-3 **(87)**	
Draft 2 BAL-005-1 Clean **(33)** | Redline to Last Posted **(34)** FAC-001-3 Clean **(35)** | Redline to Last Posted **(36)**	Additional Ballots and Non-binding Polls The ballots and non-binding poll for this posting are **additional** (even though the system shows them as initial). The standards were previously balloted together	12/31/15 - 01/11/16	Summary **(65)** Ballot Results BAL-005-1 **(66)** BAL-006-2 **(67)**	

Implementation Plans BAL-005-1 Clean **(37)** | Redline to Last Posted **(38)** BAL-006-2 Clean **(39)** | Redline to Last Posted **(40)** FAC-001-3 **(41)** **Supporting Materials** Unofficial Comment Form (Word) **(42)** Mapping Documents BAL-005-1 Clean **(43)** | Redline to Last Posted **(44)** BAL-006-2 Clean **(45)** | Redline to Last Posted **(46)** FAC-001-3 Clean **(47)** | Redline to Last Posted **(48)** VRF/VSL Justifications BAL-005-1 **(49)** FAC-001-3 **(50)** White Paper **(51)** Draft RSAWs BAL-005-1 FAC-001-3	and are now balloting separately. **Note:** A non-binding poll will not be conducted for BAL-006-2 due to its recommended retirement. Updated Info **(63)** Info **(64)** Vote		FAC-001-3 **(68)** Non-binding Poll Results BAL-005-1 **(69)** FAC-001-3 **(70)**	
	Comment Period Info **(60)** Submit Comments	11/10/15 - 01/11/16	Comments Received **(61)**	Consideration of Comments **(62)**
	Info **(59)** Send RSAW feedback to: RSAWfeedback@nerc.net	11/24/15 - 01/11/16		
White Paper **(52)** **Supporting Materials** Unofficial Survey Form (Word) **(53)** BAL-006-2 Recommended Revisions Clean **(54)** | Redline **(55)**	Survey Period Info **(56)** Submit Responses	09/16/15 - 09/25/15	Comments Received **(57)**	Consideration of Comments **(58)**
Draft 1	Initial Ballot and Non-binding Poll Updated Info **(24)**	09/04/15 - 09/14/15	Summary **(28)** Ballot Results **(29)**	

BAL-005-1 (11) BAL-006-3 Clean (12) | Redline to Last Approved (13) FAC-001-3 Clean (14) | Redline to Last Approved (15) Implementation Plans BAL-005-1 (16) BAL-006-3 (17) FAC-001-3 (18) **Supporting Materials** Unofficial Comment Form (Word) (19) Mapping Documents BAL-005-1 (20) BAL-006-3 (21) FAC-001-3 (22) (Updated) White Paper (23) (New) Draft RSAWs BAL-005-1 FAC-001-3	Info (25) Vote		Non-binding Poll Results (30)	
	Comment Period Info (26) Submit Comments	07/30/15 - 09/14/15	Comments Received (31)	Consideration of Comments (32)
	Join Ballot Pools	07/30/15 - 08/28/15		
	Info (27) Send RSAW feedback to: RSAWfeedback@nerc.net	08/14/15 - 09/14/15		
Project 2010-14.2 Periodic Review of BAL Standards Reference Material				
Final Standard Authorization Request (SAR) (1)				
SAR **BAL-005 and BAL-006** Clean (2) / Redline to Last Posted (3)	Comment Period Info (7) Submit Comments	07/16/14 - 08/14/14	Comments Received (9)	Consideration of Comments (10)

Supporting Documents Unofficial Comment Form (Word) **(4)** Recommendation to Revise BAL-005 and BAL-006 **(5)** Unofficial Nomination Form (Word) **(6)**	Nomination Period Info **(8)** Submit Nominations	07/16/14 - 07/30/14		

Standards Authorization Request Form

When completed, please email this form to: sarcomm@nerc.com.

NERC welcomes suggestions to improve the reliability of the Bulk-Power System through improved Reliability Standards. Please use this Standard Authorization Request (SAR) form to submit your request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard.

Request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard			
Title of Proposed Reliability Standard:	BAL-005-3 – Automatic Generation Control and BAL-006-3 – Inadvertent Interchange		
Date Submitted:	February 18, 2014		
SAR Requester Information			
Name:	Doug Hils		
Organization:	Duke Energy		
Telephone:	513.287.2149	Email:	doug.hils@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Reliability Standard		☐ Retirement of existing Reliability Standard	
☒ Revision to existing Reliability Standards		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard. Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls (BARC 2) was included in the current cycle of periodic reviews.

SAR Information
The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0_2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. As a result of that examination, the BARC 2 PRT recommends to REVISE BAL-005-0_2b and BAL-006-2, and has therefore developed this Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revisions.
Purpose or Goal (How does this request propose to address the problem described above?):
This SAR proposes revising BAL-005 and BAL-006 in line with the recommendations of the BARC 2 PRT as described in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1). The proposed changes to the standards add clarity, remove redundancy, take into account technological changes since the last versions of the standards, address FERC directives, and bring compliance elements in accordance with NERC guidelines. A detailed description of the PRT's recommended changes are contained later in this SAR.
Identify the Objectives of the proposed Reliability Standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of BAL-005 is to establish requirements for acquiring necessary data for the Balancing Authority to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. The current objective of BAL-006 is to define a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations. As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under this SAR.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this Reliability Standard action.)
The scope of this standard action is to revise BAL-005 and BAL-006 in accordance with the recommendations made by the PRT in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1), and consistent with industry consensus to make additional standard revisions to the extent such consensus develops.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the Reliability Standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the Reliability Standard action.)

1. BAL-005

The BARC2 PRT has completed its review of BAL-005, and, among other recommendations, proposes certain revisions below which would remove references to the types of resources and reserves utilized by the Balancing Authority to balance resources and demand. The PRT recommendations focus on the components that make up the Reporting ACE, and not on the ancillary service aspects of resource control that drew criticism from the industry for being specific to generation when BAL-005 was originally filed with the FERC. Among other recommendations, for the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules (all similar in that they utilize real-time data from an agreed-upon common source between Adjacent BAs), the PRT recommends requirements which are focused on Real-time operating data. The PRT's recommendations for BAL-005 are fully detailed below.

1) **Title**: The PRT recommends changing the title of BAL-005 to "Balancing Authority Control" to remove the implication that BAL-005 pertains exclusively to generation, and better reflect the focus on the BA acquiring necessary data to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. Based upon the input from the industry, the PRT recommends that the SDT consider whether the term AGC should be retained within any requirements. The PRT also recommends that the SDT pursue revisions to the definition of AGC as proposed below to be resource-neutral.

AGC: Equipment that automatically adjusts ~~generation~~ resources utilized in a Balancing Authority Area from a central location to maintain the Balancing Authority's Reporting ACE within the bounds required under the NERC Reliability Standards. Resources utilized under AGC may include conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response. ~~may interchange~~

SAR Information
~~schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~ 2) **Purpose**: The SDT would also be tasked with consideration of revising the "Purpose" statement to focus on acquiring the information necessary for calculating Reporting ACE, while remaining neutral on the types of reserves or resources utilized. The PRT recommends the following revised Purpose statement for SDT consideration: This standard establishes requirements for acquiring necessary data for the Balancing Authority so that balancing of resources and demand can be achieved under Tie-Line Bias Control. Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception. 3) **Applicability**: The SDT should remove "Generator Operators", "Transmission Operators", and "Load Serving Entities" as applicable entities unless specificially added into a Standard requirement by the SDT. 4) **Requirement R1**: The PRT recommends that the content of Requirement R1 be split between what is needed for ensuring facilities are within a BA Area prior to MW being generated or consumed, and what is needed for ensuring balanced operation within an Interconnection. First, the PRT recommends that the SDT consider continuing discussions with the FAC SDT regarding moving and restating or clarifying the TOP, LSE, and GOP requirements in a FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT discussed that the ownership of metering and other factors may drive why the LSE is included in this standard, along with other entities; however, consideration should be given to moving requirements for these facilities to be within a BA Area into a FAC standard. The PRT is concerned that removing any such requirements of the LSE, TOP, and GOP and not reflecting them within another standard may inadvertently transfer certain obligations to the BA to ensure that such loads, resources, and facilities are within the BA's metered boundaries. The SDT should explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary. Second, the PRT recommends that the SDT revise Requirements R1 and R2 to be BA requirements that all Actual Net Interchange and Scheduled Net Interchange used by the

SAR Information
BA in its Reporting ACE calculation also have an Adjacent BA, as proposed in the redlined Requirements R1 and R2. Note that the PRT does not intend with the proposed language to impose any additional requirements on the BA that currently apply to the LSE, GOP, and TOP, but also believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example) or a FAC requirement. With respect to proposed R2, the SDT should ensure that the requirement cannot be misinterpreted to imply that Dynamic Schedules can only be with physically adjacent BAs. The intent is to address adjacency in a manner consistent with the scheduling path no differently than used for interchange schedules. 5) **Requirement R2**: Retirement approved by FERC effective January 21, 2014. 6) **Requirement R3**: The PRT recommends that the SDT not use the term "Regulation Service," as in general this statement could apply to implementation of Dynamic Schedules or Pseudo-Ties, and the desire to have a common point for the data shared between the BAs implementing the Dynamic Transfer. The PRT recommends removing "adequate" and "Burden" from the requirement. The PRT recommends expanding Requirement R3 to be applicable to the implementation of tie lines, Pseudo-Ties, and Dynamic Schedules, as all require agreement between adjacent BAs on the agreed-upon points to be implemented. The PRT recommends that the SDT review the other standards such as TOP-005 to assure there is no duplication or redundancy specific to the concern on swapping hourly values in BAL-005 posted for industry comment. The PRT recommends deleting the proposed R3.2 and the first sentence of the proposed R3.5.2. The PRT also recommends the SDT develop a guideline document to accompany BAL-005 covering some of the suggested best practices. 7) **Requirement R4**: The PRT reviewed Requirement R4 with respect to what notification or coordination is necessary that could be considered with the other requirements in this Standard regarding Interchange. Initially the PRT was considering a recommendation that the SDT consider the requirement as it applies to Dynamic Transfer implementation as discussed in the Dynamic Transfer reliability guideline, and as it applies to the practice of implementing multiple-BA Dynamic Transfers under a process referred to as ACE Diversity Interchange. The PRT also considered recommendations to delete or modify Requirement R4 so that it requires communication with not only the BAs, but any other affected entities, and also to strike "providing Regulation Service." However, after further review, the PRT recommends retiring Requirement R4, as the basis for coordination of common values between adjacent BAs is covered in Requirement R3, and correction of information not available has also been addressed. These requirements should ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

SAR Information
8) **Requirement R5**: The PRT recommends retiring Requirement R5, as the requirements placed upon the implementation of Dynamic Transfers are covered within Requirement R3. With respect to having a backup plan to the extent that a service may no longer be provided, the PRT believes this would be covered in the terms agreed to between the parties implementing the Dynamic Transfer. As proposed by the PRT, the requirements remaining in BAL-005 would ensure that any failure to perform would be reflected in the BA performance under BAL-001-2. 9) **Requirement R6**: The PRT recommends that the sentence "Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control" be captured in the definition of "Reporting ACE.". The terms used in Requirement R6 need to be consistent with those used in Reporting ACE if the Requirement is retained. The SDT should consider whether the 30-minute requirement for RC notification is sufficient or excessive. The PRT recommends that if a timing requirement remains in the standard that it be structured in a manner to not require communication with the RC if the capability to calculate Reporting ACE is restored within the defined notification period. 10) **Requirement R7**: The PRT recommends retiring this Requirement under Paragraph 81. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, which can be done manually without any detriment to reliability. EOP-008-1 Requirement R1 recognizes that such automated capability may not be available for up to two hours for loss of control center functionality. In addition, the second sentence is not needed, as such actions would be covered under EOP-008. The PRT believes that the term "Operating AGC" in Requirement R7 refers to the capability to continuously calculate ACE (not automatic control of resources), which should be considered one of the BAs functional obligations with regard to the reliable operations and situational awareness of the BES. Though redundancy and other provisions may be in place to maintain EMS functionality, there are times when the information may not be available where the provisions under EOP-008-1 would apply. 11) **Requirement R8**: The PRT recommends that the SDT revise the Requirement with the proper context of a minimum normal scan rate and clarify how frequently all components must be factored into the Reporting ACE equation under normal operation. With respect to the sub-requirements, the SDT should ensure that any proposed revisions accommodate abnormal and emergency operations, including the possibility that the EMS or supporting telemetry may not be available, such as during an evacuation to a backup site. The PRT notes that the SDT should consider a requirement focused on a minimum scan-rate expectation under normal operations, rather than a requirement that could be interpreted as if systems have 100% availability.

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12) **Requirement R8, Part 8.1**: The BA should have visibility of system frequency within parameters consistent with EOP-008, however the PRT recommends that the requirement not be prescriptive. The SDT should review EOP-008 to ensure that this requirement is covered there. In addition, the SDT should also consider remote and redundant frequency resources to the extent that the information that is otherwise available to the BA may not be available upon loss of control center functionality. Such capability may already be anticipated under EOP-008. The SDT should consider the following questions in the development of the revised requirement: a) How much time is allowed to pass if the redundancy is lost before it must be restored? b) Does the PRT believe it is acceptable for the second and independent frequency device to be one used by another Balancing Authority? 13) **Requirement R9, Part 9.1**: The PRT recommends retiring this Requirement. The Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use. By focusing on real-time Reporting ACE, we are assuring reliability is addressed and maintained at all times. 14) **Requirement R10 and R11**: The PRT recommends retiring these requirements, as the basics of both requirements are factored into the definition of Scheduled Net Interchange used in the Reporting ACE calculation as defined in the NERC Glossary. The PRT noted that Requirement R10 is written as if "Net Scheduled Interchange" is the value used in the ACE equation; however, Net Scheduled Interchange has two meanings – the algebraic sum of all Interchange Schedules across a given path, or between Balancing Authorities for a given period or instant in time. Aside from the concern of having a definition with two different meanings, the PRT believes that neither choice in the definition accurately depicts the value inserted into the ACE or Reporting ACE, which would be the algebraic sum of all Net Scheduled Interchange with all Adjacent Balancing Authorities, including Dynamic Schedules. In addition, the PRT could not find a definition of Scheduled Interchange as used in Requirement R11. Under Section 3 below, the PRT recommends changes to certain NERC definitions.

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15) **Requirement R12**: The PRT took a holistic approach to Requirement R12 and other requirements related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, as all relate to the information exchanged between adjacent BAs. The PRT recommends a new Requirement R3 related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, where each respective Adjacent BA has agreed to common measuring points that produce an agreed-to value to be included in the calculation of Reporting ACE. The SDT should review the requirement as it relates to current practices to ensure the reliability needs are met. The PRT suggests that the holistic approach shall only be achieved if there is a comprehensive definition of ACE. Therefore, the PRT recommends the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). The PRT notes that the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary. The PRT suggests that a complete review of all the NERC Standards for use of the term “ACE” is necessary to assure that any update to the ACE definition would not impact any other Standard. 16) **Requirement R13**: The PRT suggests deleting the first sentence of R13, and suggests that the SDT include in a guideline document the practice of performing hourly error checks of the Actual Net Interchange ($NI_{A)}$ operated to for the hour against an end-of-the-hour reference. The PRT also recommends a separate requirement specific to adjustments as needed to the Reporting ACE to reflect the meter error adjustment. However, the PRT is concerned that requiring correction of a component of ACE when in error (no matter how negligible) would be problematic in that not all errors require correction. The PRT recommends that the SDT consider stating the requirement in such a manner that I_{ME} is required to be zero except during times needed to compensate for any data or equipment error affecting a component of the Reporting ACE calculation (interchange or frequency). When writing the requirement, the SDT should also consider that there are other means of addressing metering corrections besides use of the IME term, which may include possible revision to real-time metering data. Uses of the I_{ME} term in the Reporting ACE may also be an appropriate subject for the guideline document the PRT is

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recommending that the SDT develop to accompany BAL-005 covering some of the suggested best practices. **Requirement R14**: The PRT recommends that the SDT delete the first sentence in R14 and revise the second sentence to cover the minimum amount of information expected for the BA to provide in real-time to its operator. The PRT also recommends that the individual components of actual and scheduled interchange with each Adjacent Balancing Authority also be captured (Tie-Lines, Pseudo-Ties, Dynamic Schedules, block schedules as needed for coordination, and real-time schedules). Based on industry comments, the SDT should consider whether this requirement is needed in the BAL standards, whether it is adequately covered elsewhere in the standards, or whether it should be moved to the NERC Rules of Procedure for certification of the Functional Entity. 17) **Requirement R15**: The SDT should consider placing a requirement in a FAC Standard with respect to supporting infrastructure or functionality, or review EOP-008 to determine if existing requirements adequately address primary control center functionality. 18) **Requirement R16**: The PRT recommends moving the requirement for flagging bad data to revisions made in Requirement R14. 19) **Requirement R17**: The PRT recommends that this requirement be written to be specific to the equipment used to determine the frequency component required for Reporting ACE. The PRT also recommends that the SDT move any accuracy requirements applicable to the needs of the Transmission Operator, (which may include MW, MVAR, voltage, potential transformer, current transformer, and remote terminal unit or equivalent) to a TOP or FAC standard. Further study would be needed on the ".25% of full scale" and the "appropriate accuracy" language. **2. BAL-006** The BARC2 PRT has completed its review of BAL-006 and recommends that it be revised. The recommendations below include moving any requirements with implications for real-time operations into BAL-005. Among other work, the review team considered a FERC directive that recommended the development of a metric to bound the magnitude of inadvertent accumulations, as those accumulations may be indicative of a BA excessively leaning on the resources of others in its Interconnection. The review team

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consensus was that an Inadvertent Interchange accumulation value alone cannot yield useful information concerning whether a BA is operating reliably. The PRT document on the consideration of issues and directives more fully covers the PRT recommendations related to the FERC directives. The PRT's recommendations for BAL-006 are fully detailed below. 1) **Purpose**: As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this recommendation. 2) **Requirement R1**: The PRT recommends removing Requirement R1 as written and recommends that the SDT determine if there is merit in developing a reliability metric specific to this standard to measure performance to certain requirements under BAL-006, including the consideration of including the calculation of Inadvertent Interchange. In development of any metric, the PRT recommends that the SDT determine the appropriate time-frame for reliability (as close to real-time as possible). Similar to how BAL-001-2 has CPS1 and BAAL measures dependent upon the BA calculating its Reporting ACE without a stated requirement that "Each BA shall calculate its Reporting ACE", the PRT felt that if the industry supports a measure being developed that uses Inadvertent Interchange in the measure of performance, that the BA would calculate Inadvertent Interchange as needed to comply. Also, similar to the approach taken for defining Reporting ACE in the Glossary with all of the components necessary for the calculation, the PRT is recommending in Requirement R2 below that the definition of Inadvertent Interchange also be updated so that all components necessary for the calculation are identified. 3) **Requirement R2**: The PRT recommends incorporating Requirement R2 into a revised definition of Inadvertent Interchange: The PRT recommends that this definition be modified to capture that the calculation is on an hourly basis and includes the megawatt-hour values for Tie-Lines, Pseudo-Ties, and Dynamic Schedules, along with other scheduled interchange implemented under block scheduling, which does not include the effect of the ramps. The PRT recommends that the definition also include the NERC definitions of On-Peak Accounting and Off-Peak Accounting, which reference the NAESB business practice for inadvertent interchange accounting. The PRT also recommends that the definition clarify the treatment of scheduled and actual interchange associated with asynchronous ties between Interconnections. 4) **Requirement R3**: The PRT recommends incorporating Requirement R3 into BAL-005, as the requirement relates to the agreement on common values used in Real-time and also

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recommends developing a guideline to cover the practice of comparing the hourly megawatt-hour values gathered at the end of the hour against the hourly integrated values of the scan-rate data operated to, in order to determine if significant error exists. 5) **Requirement R4**: The SDT should review current practices for confirmation of interchange after-the-fact to determine and justify a shorter duration for agreement on such values for reliability purposes. The PRT also recommends that Requirement R4 be restated to require that the agreement is based upon the aggregate net schedules and net actuals by adjacent BAs as further defined in the new definition of Inadvertent Interchange. In concept, every Tie-Line, Pseudo-Tie, and Interchange Schedule (including Dynamic Schedules) implemented in the Reporting ACE calculation should have an accompanying after-the-fact megawatt-hour value accounted for in the calculation of Inadvertent Interchange. 6) **Requirement R4, Part 4.2**: The SDT should evaluate whether to retire this Requirement, as it is addressed in the new definition of Inadvertent Interchange by the proposed reference to On-Peak Accounting and Off-Peak Accounting. 7) **Requirement R4.3**: The SDT should review this requirement to determine what elements of the requirement are necessary to support reliability. The SDT also should consider including in a guideline document a practice to support providing operations personnel with information on the comparison of monthly revenue class meters to meters used for real-time operation. 8) **Requirement R5**: The SDT should review whether the practice that requires BAs to mutually agree by the 15th calendar day is needed for reliability. The PRT believes there may be merit in requiring BAs to identify the cause of the dispute, and to either correct it within a prescribed number of days, or follow a dispute resolution process. The SDT should ensure that the requirement is clear and distinct, which may require modifying or striking the language regarding dispute resolution.

Reliability Functions		
The Reliability Standards will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.

Reliability Functions		
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Reliability Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Reliability Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.	Yes.
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure.	Yes.
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.	Yes.

Reliability and Market Interface Principles	
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.	Yes.

Related Reliability Standards	
Reliability Standard No.	Explanation
BAL-001-2 and draft BAL-002-2	Some of the proposed revisions to BAL-005 focus on the components used to calculate Reporting ACE, used to measure compliance to CPS1 and BAAL in BAL-001-2, and measure compliance in the draft BAL-002-2 revisions.
EOP-008-1	The purpose of EOP-008-1 is to ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable. For certain proposed revisions to BAL-005 in this SAR, the PRT recommends that the SDT consider provisions in EOP-008-1 for the loss of control center functionality.
FAC-001-1	With respect to BAL-005 Requirement R1, the PRT recommends that the SDT consider moving and restating the TOP, LSE, and GOP requirements in an FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT recommends that the SDT explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary.
Other	The PRT recommendations include that the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). As the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary, the PRT suggests that a complete review of all the NERC Standards is necessary to assure where ACE is utilized in a Standard, that any update to the ACE definition would not impact any other Standard.

Related SARs – N/A	
SAR ID	Explanation

Regional Variances – N/A	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to: sarcomm@nerc.com.

NERC welcomes suggestions to improve the reliability of the Bulk-Power System through improved Reliability Standards. Please use this Standard Authorization Request (SAR) form to submit your request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard.

Request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard			
Title of Proposed Reliability Standard:	BAL-005-3 – Automatic Generation Control and BAL-006-3 – Inadvertent Interchange		
Date Submitted:	February 18, 2014		
SAR Requester Information			
Name:	Doug Hils		
Organization:	Duke Energy		
Telephone:	513.287.2149	Email:	doug.hils@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Reliability Standard		☐ Retirement of existing Reliability Standard	
☒ Revision to existing Reliability Standards		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard. Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls (BARC 2) was included in the current cycle of periodic reviews.

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The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0_2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. As a result of that examination, the BARC 2 PRT recommends to REVISE BAL-005-0_2b and BAL-006-2, and has therefore developed this Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revisions.
Purpose or Goal (How does this request propose to address the problem described above?):
This SAR proposes revising BAL-005 and BAL-006 in line with the recommendations of the BARC 2 PRT as described in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1). The proposed changes to the standards add clarity, remove redundancy, take into account technological changes since the last versions of the standards, address FERC directives, and bring compliance elements in accordance with NERC guidelines. A detailed description of the PRT's recommended changes are contained later in this SAR.
Identify the Objectives of the proposed Reliability Standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of BAL-005 is to establish requirements for acquiring necessary data for the Balancing Authority to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. The current objective of BAL-006 is to define define a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations. As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under this SAR.

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Brief Description (Provide a paragraph that describes the scope of this Reliability Standard action.)
The scope of this standard action is to revise BAL-005 and BAL-006 in accordance with the recommendations made by the PRT in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1), and consistent with industry consensus to make additional standard revisions to the extent such consensus develops.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the Reliability Standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the Reliability Standard action.)

1. BAL-005

The BARC2 PRT has completed its review of BAL-005, and, among other recommendations, proposes certain revisions below which would remove references to the types of resources and reserves utilized by the Balancing Authority to balance resources and demand. The PRT recommendations focus on the components that make up the Reporting ACE, and not on the ancillary service aspects of resource control that drew criticism from the industry for being specific to generation when BAL-005 was originally filed with the FERC. Among other recommendations, for the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules (all similar in that they utilize real-time data from an agreed-upon common source between Adjacent BAs), the PRT recommends requirements focused on the real-time values operated to. The PRT's recommendations for BAL-005 are fully detailed below.

1) **Title**: The PRT recommends changing the title of BAL-005 to "Balancing Authority Control" to remove the implication that BAL-005 pertains exclusively to generation, and better reflect the focus on the BA acquiring necessary data to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. Based upon the input from the industry, the PRT recommends that the SDT consider whether the term AGC should be retained within any requirements. The PRT also recommends that the SDT pursue revisions to the definition of AGC as proposed below to be resource-neutral.

AGC: Equipment that automatically adjusts ~~generation~~ resources utilized in a Balancing Authority Area from a central location to maintain the Balancing Authority's Reporting ACE within the bounds required under the NERC Reliability Standards. Resources utilized under AGC may include conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response. ~~may interchange~~

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~~schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~

2) **Purpose**: The SDT would also be tasked with consideration of revising the "Purpose" statement to focus on acquiring the information necessary for calculating Reporting ACE, while remaining neutral on the types of reserves or resources utilized. The PRT recommends the following revised Purpose statement for SDT consideration:

   > This standard establishes requirements for acquiring necessary data for the Balancing Authority so that balancing of resources and demand can be achieved under Tie-Line Bias Control.

   Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception.

3) **Applicability**: The SDT should remove "Generator Operators", "Transmission Operators", and "Load Serving Entities" as applicable entities unless specificially added into a Standard requirement by the SDT.

4) **Requirement R1**: The PRT recommends that the content of Requirement R1 be split between what is needed for ensuring facilities are within a BA Area prior to MW being generated or consumed, and what is needed for ensuring balanced operation within an Interconnection. First, the PRT recommends that the SDT consider continuing discussions with the FAC SDT moving and restating or clarifying the TOP, LSE, and GOP requirements in a FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT discussed that the ownership of metering and other factors may drive why the LSE is included in this standard, along with other entities; however, consideration should be given to moving requirements for these facilities to be within a BA Area into a FAC standard. The PRT is concerned that removing any such requirements of the LSE, TOP, and GOP and not reflecting them within another standard may inadvertently transfer certain obligations to the BA to ensure that such loads, resources, and facilities are within the BA's metered boundaries. The SDT should explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary. Second, the PRT recommends that the SDT revise Requirements R1 and R2 to be BA requirements that all Actual Net Interchange and Scheduled Net Interchange used by the BA in its Reporting ACE

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calculation also have an Adjacent BA, as proposed in the redlined Requirements R1 and R2. Note that the PRT does not intend with the proposed language to impose any additional requirements on the BA that currently apply to the LSE, GOP, and TOP, but also believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example) or a FAC requirement. With respect to proposed R2, the SDT should ensure that the requirement cannot be misinterpreted to imply that Dynamic Schedules can only be with physically adjacent BAs. The intent is to address adjacency in a manner consistent with the scheduling path no differently than used for interchange schedules. 5) **Requirement R2**: Retirement approved by FERC effective January 21, 2014. 6) **Requirement R3**: The PRT recommends that the SDT not use the term "Regulation Service," as in general this statement could apply to implementation of Dynamic Schedules or Pseudo-Ties, and the desire to have a common point for the data shared between the BAs implementing the Dynamic Transfer. The PRT recommends removing "adequate" and "Burden" from the requirement. The PRT recommends expanding Requirement R3 to be applicable to the implementation of tie lines, Pseudo-Ties, and Dynamic Schedules, as all require agreement between adjacent BAs on the agreed-upon points to be implemented. The PRT recommends that the SDT review the other standards such as TOP-005 to assure there is no duplication or redundancy. Specific to the concern on swapping hourly values in BAL-005 posted for industry comment. The PRT recommends deleting the proposed R3.2 and the first sentence of the proposed R3.5.2, the PRT also recommends the SDT develop a guideline document to accompany BAL-005 covering some of the suggested best practices. 7) **Requirement R4**: The PRT reviewed Requirement R4 with respect to what notification or coordination is necessary that could be considered with the other requirements in this Standard regarding Interchange. Initially the PRT was considering a recommendation that the SDT consider the requirement as it applies to Dynamic Transfer implementation as discussed in the Dynamic Transfer reliability guideline, and as it applies to the practice of implementing multiple-BA Dynamic Transfers under a process referred to as ACE Diversity Interchange. The PRT also considered recommendations to delete or modify Requirement R4 so that it requires communication with not only the BAs, but any other affected entities, and also to strike "providing Regulation Service." However, after further review, the PRT recommends retiring Requirement R4, as the basis for coordination of common values between adjacent BAs is covered in Requirement R3, and correction of information not available has also been addressed. These requirements should ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

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8) **Requirement R5**: The PRT recommends retiring Requirement R5, as the requirements placed upon the implementation of Dynamic Transfers are covered within Requirement R3. With respect to having a backup plan to the extent that a service may no longer be provided, the PRT believes this would be covered in the terms agreed to between the parties implementing the Dynamic Transfer. As proposed by the PRT, the requirements remaining in BAL-005 would ensure that any failure to perform would be reflected in the BA performance under BAL-001-2. 9) **Requirement R6**: The PRT recommends that the sentence "Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control" be captured in the definition of "Reporting ACE.". The terms used in the Requirement R6 need to be consistent with those used in Reporting ACE if the Requirement is retained. The SDT should consider whether the 30-minute requirement for RC notification is sufficient or excessive. The PRT recommends that if a timing requirement remains in the standard that it be structured in a manner to not require communication with the RC if the capability to calculate Reporting ACE is restored within the defined notification period. 10) **Requirement R7**: The PRT recommends retiring this Requirement under Paragraph 81. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, which can be done manually without any detriment to reliability. EOP-008-1 Requirement R1 recognizes that such automated capability may not be available for up to two hours for loss of control center functionality. In addition, the second sentence is not needed, as such actions would be covered under EOP-008. The PRT believes that the term "Operating AGC" in Requirement R7 refers to the capability to continuously calculate ACE (not automatic control of resources), which should be considered one of the BAs functional obligations with regard to the reliable operations and situational awareness of the BES. Though redundancy and other provisions may be in place to maintain EMS functionality, there are times when the information may not be available where the provisions under EOP-008-1 would apply. 11) **Requirement R8**: The PRT recommends that the SDT revise the Requirement with the proper context of a minimum normal scan rate and clarify how frequently all components must be factored into the Reporting ACE equation under normal operation. With respect to the sub-requirements, the SDT should ensure that any proposed revisions accommodate abnormal and emergency operations, including the possibility that the EMS or supporting telemetry may not be available, such as during an evacuation to a backup site. The PRT notes that the SDT should consider a requirement focused on a minimum scan-rate expectation under normal operations, rather than a requirement that could be interpreted as if systems have 100% availability.

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12) **Requirement R8, Part 8.1**: The BA should have visibility of system frequency within parameters consistent with EOP-008, however the PRT recommends that the requirement not be prescriptive. The SDT should review EOP-008 to ensure that this requirement is covered there. In addition, the SDT should also consider remote and redundant frequency resources to the extent that the information that is otherwise available to the BA may not be available upon loss of control center functionality. Such capability may already be anticipated under EOP-008. The SDT should consider the following questions in the development of the revised requirement: a) How much time is allowed to pass if the redundancy is lost before it must be restored? b) Does the PRT believe it is acceptable for the second and independent frequency device to be one used by another Balancing Authority? 13) **Requirement R9, Part 9.1**: The PRT recommends retiring this Requirement. The Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use. By focusing on real-time Reporting ACE, we are assuring reliability is addressed and maintained at all times. 14) **Requirement R10 and R11**: The PRT recommends retiring these requirements, as the basics of both requirements are factored into the definition of Scheduled Net Interchange used in the Reporting ACE calculation as defined in the NERC Glossary. The PRT noted that Requirement R10 is written as if "Net Scheduled Interchange" is the value used in the ACE equation; however, Net Scheduled Interchange has two meanings – the algebraic sum of all Interchange Schedules across a given path, or between Balancing Authorities for a given period or instant in time. Aside from the concern of having a definition with two different meanings, the PRT believes that neither choice in the definition accurately depicts the value inserted into the ACE or Reporting ACE, which would be the algebraic sum of all Net Scheduled Interchange with all Adjacent Balancing Authorities, including Dynamic Schedules. In addition, the PRT could not find a definition of Scheduled Interchange as used in Requirement R11. Under Section 3 below, the PRT recommends changes to certain NERC definitions.

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15) **Requirement R12**: The PRT took a holistic approach to Requirement R12 and other requirements related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, as all relate to the information exchanged between adjacent BAs. The PRT recommends a new Requirement R3 related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, where each respective Adjacent BA has agreed to common measuring points that produce an agreed-to value to be included in the calculation of Reporting ACE. The SDT should review the requirement as it relates to current practices to ensure the reliability needs are met. The PRT suggests that the holistic approach shall only be achieved if there is a comprehensive definition of ACE. Therefore, the PRT recommends the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). The PRT notes that the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary. The PRT suggests that a complete review of all the NERC Standards for use of the term “ACE” is necessary to assure that any update to the ACE definition would not impact any other Standard. 16) **Requirement R13**: The PRT suggests deleting the first sentence of R13, and suggests that the SDT include in a guideline document the practice of performing hourly error checks of the Actual Net Interchange ($NI_{A)}$ operated to for the hour against an end-of-the-hour reference. The PRT also recommends a separate requirement specific to adjustments as needed to the Reporting ACE to reflect the meter error adjustment. However, the PRT is concerned that requiring correction of a component of ACE when in error (no matter how negligible) would be problematic in that not all errors require correction. The PRT recommends that the SDT consider stating the requirement in such a manner that I_{ME} is required to be zero except during times needed to compensate for any data or equipment error affecting a component of the Reporting ACE calculation (interchange or frequency). When writing the requirement, the SDT should also consider that there are other means of addressing metering corrections besides use of the I_{ME} term, which may include possible revision to real-time metering data. Uses of the I_{ME} term in the Reporting ACE may also be an appropriate subject for the guideline document the PRT is

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recommending that the SDT develop to accompany BAL-005 covering some of the suggested best practices. **Requirement R14**: The PRT recommends that the SDT delete the first sentence in R14 and revise the second sentence to cover the minimum amount of information expected for the BA to provide in real-time to its operator. The PRT also recommends that the individual components of actual and scheduled interchange with each Adjacent Balancing Authority also be captured (Tie-Lines, Pseudo-Ties, Dynamic Schedules, block schedules as needed for coordination, and real-time schedules). Based on industry comments, the SDT should consider whether this requirement is needed in the BAL standards, whether it is adequately covered elsewhere in the standards, or whether it should be moved to the NERC Rules of Procedure for certification of the Functional Entity. 17) **Requirement R15**: The SDT should consider placing a requirement in a FAC Standard with respect to supporting infrastructure or functionality, or review EOP-008 to determine if existing requirements adequately address primary control center functionality. 18) **Requirement R16**: The PRT recommends moving the requirement for flagging bad data to revisions made in Requirement R14. 19) **Requirement R17**: The PRT recommends that this requirement be written to be specific to the equipment used to determine the frequency component required for Reporting ACE. The PRT also recommends that the SDT move any accuracy requirements applicable to the needs of the Transmission Operator, (which may include MW, MVAR, voltage, potential transformer, current transformer, and remote terminal unit or equivalent) to a TOP or FAC standard. Further study would be needed on the ".25% of full scale" and the "appropriate accuracy" language. **2. BAL-006** The BARC2 PRT has completed its review of BAL-006 and recommends that it be revised. The recommendations below include moving any requirements with implications for real-time operations into BAL-005. Among other work, the review team considered a FERC directive that recommended the development of a metric to bound the magnitude of inadvertent accumulations, as those accumulations may be indicative of a BA excessively leaning on the resources of others in its Interconnection. The review team

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consensus was that an Inadvertent Interchange accumulation value alone cannot yield useful information concerning whether a BA is operating reliably. The PRT document on the consideration of issues and directives more fully covers the PRT recommendations related to the FERC directives. The PRT's recommendations for BAL-006 are fully detailed below. 1) **Purpose**: As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this recommendation. 2) **Requirement R1**: The PRT recommends removing Requirement R1 as written and recommends that the SDT determine if there is merit in developing a reliability metric specific to this standard to measure performance to certain requirements under BAL-006, including the consideration of including the calculation of Inadvertent Interchange. In development of any metric, the PRT recommends that the SDT determine the appropriate time-frame for reliability (as close to real-time as possible). Similar to how BAL-001-2 has CPS1 and BAAL measures dependent upon the BA calculating its Reporting ACE without a stated requirement that "Each BA shall calculate its Reporting ACE", the PRT felt that if the industry supports a measure being developed that uses Inadvertent Interchange in the measure of performance, that the BA would calculate Inadvertent Interchange as needed to comply. Also, similar to the approach taken for defining Reporting ACE in the Glossary with all of the components necessary for the calculation, the PRT is recommending in Requirement R2 below that the definition of Inadvertent Interchange also be updated so that all components necessary for the calculation are identified. 3) **Requirement R2**: The PRT recommends incorporating Requirement R2 into a revised definition of Inadvertent Interchange: The PRT recommends that this definition be modified to capture that the calculation is on an hourly basis and includes the megawatt-hour values for Tie-Lines, Pseudo-Ties, and Dynamic Schedules, along with other scheduled interchange implemented under block scheduling, which does not include the effect of the ramps. The PRT recommends that the definition also include the NERC definitions of On-Peak Accounting and Off-Peak Accounting, which reference the NAESB business practice for inadvertent interchange accounting. The PRT also recommends that the definition clarify the treatment of scheduled and actual interchange associated with asynchronous ties between Interconnections. 4) **Requirement R3**: The PRT recommends incorporating Requirement R3 into BAL-005, as the requirement relates to the agreement on common values used in Real-time and also

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recommends developing a guideline to cover the practice of comparing the hourly megawatt-hour values gathered at the end of the hour against the hourly integrated values of the scan-rate data operated to, in order to determine if significant error exists. 5) **Requirement R4**: The SDT should review current practices for confirmation of interchange after-the-fact to determine and justify a shorter duration for agreement on such values for reliability purposes. The PRT also recommends that Requirement R4 be restated to require that the agreement is based upon the aggregate net schedules and net actuals by adjacent BAs as further defined in the new definition of Inadvertent Interchange. In concept, every Tie-Line, Pseudo-Tie, and Interchange Schedule (including Dynamic Schedules) implemented in the Reporting ACE calculation should have an accompanying after-the-fact megawatt-hour value accounted for in the calculation of Inadvertent Interchange. 6) **Requirement R4, Part 4.2**: The SDT should evaluate whether to retire this Requirement, as it is addressed in the new definition of Inadvertent Interchange by the proposed reference to On-Peak Accounting and Off-Peak Accounting. 7) **Requirement R4.3**: The SDT should review this requirement to determine what elements of the requirement are necessary to support reliability. The SDT also should consider including in a guideline document a practice to support providing operations personnel with information on the comparison of monthly revenue class meters to meters used for real-time operation. 8) **Requirement R5**: The SDT should review whether the practice that requires BAs to mutually agree by the 15th calendar day is needed for reliability. The PRT believes there may be merit in requiring BAs to identify the cause of the dispute, and to either correct it within a prescribed number of days, or follow a dispute resolution process. The SDT should ensure that the requirement is clear and distinct, which may require modifying or striking the language regarding dispute resolution.

Reliability Functions		
The Reliability Standards will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.

Reliability Functions		
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Reliability Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Reliability Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.	Yes.
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure.	Yes.
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.	Yes.

Reliability and Market Interface Principles	
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.	Yes.

Related Reliability Standards	
Reliability Standard No.	Explanation
BAL-001-2 and draft BAL-002-2	Some of the proposed revisions to BAL-005 focus on the components used to calculate Reporting ACE, used to measure compliance to CPS1 and BAAL in BAL-001-2, and measure compliance in the draft BAL-002-2 revisions.
EOP-008-1	The purpose of EOP-008-1 is to ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable. For certain proposed revisions to BAL-005 in this SAR, the PRT recommends that the SDT consider provisions in EOP-008-1 for the loss of control center functionality.
FAC-001-1	With respect to BAL-005 Requirement R1, the PRT recommends that the SDT consider moving and restating the TOP, LSE, and GOP requirements in an FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT recommends that the SDT explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary.
Other	The PRT recommendations include that the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). As the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary, the PRT suggests that a complete review of all the NERC Standards is necessary to assure where ACE is utilized in a Standard, that any update to the ACE definition would not impact any other Standard.

Related SARs – N/A	
SAR ID	Explanation

Regional Variances – N/A	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Standards Authorization Request Form

When completed, please email this form to: sarcomm@nerc.com.

NERC welcomes suggestions to improve the reliability of the Bulk-Power System through improved Reliability Standards. Please use this Standard Authorization Request (SAR) form to submit your request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard.

Request to propose a new Reliability Standard, a revision to a Reliability Standard, or the retirement of a Reliability Standard			
Title of Proposed Reliability Standard:	BAL-005-3 – Automatic Generation Control and BAL-006-3 – Inadvertent Interchange		
Date Submitted:	February 18, 2014		
SAR Requester Information			
Name:	Doug Hils		
Organization:	Duke Energy		
Telephone:	513.287.2149	Email:	doug.hils@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Reliability Standard		☐ Retirement of existing Reliability Standard	
☒ Revision to existing Reliability Standards		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard. Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls (BARC 2) was included in the current cycle of periodic reviews.

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The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0_2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. As a result of that examination, the BARC 2 PRT recommends to REVISE BAL-005-0_2b and BAL-006-2, and has therefore developed this Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revisions.
Purpose or Goal (How does this request propose to address the problem described above?):
This SAR proposes revising BAL-005 and BAL-006 in line with the recommendations of the BARC 2 PRT as described in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1). The proposed changes to the standards add clarity, remove redundancy, take into account technological changes since the last versions of the standards, address FERC directives, and bring compliance elements in accordance with NERC guidelines. A detailed description of the PRT's recommended changes are contained later in this SAR.
Identify the Objectives of the proposed Reliability Standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of BAL-005 is to establish requirements for acquiring necessary data for the Balancing Authority to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. The current objective of BAL-006 is to define define a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations. As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under this SAR.

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SAR Information
Brief Description (Provide a paragraph that describes the scope of this Reliability Standard action.)
The scope of this standard action is to revise BAL-005 and BAL-006 in accordance with the recommendations made by the PRT in the *PRT Recommendation to Revise BAL-005 and BAL-006*, (Attachment 1), and consistent with industry consensus to make additional standard revisions to the extent such consensus develops.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the Reliability Standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the Reliability Standard action.)

1. BAL-005

The BARC2 PRT has completed its review of BAL-005, and, among other recommendations, proposes certain revisions below which would remove references to the types of resources and reserves utilized by the Balancing Authority to balance resources and demand. The PRT recommendations focus on the components that make up the Reporting ACE, and not on the ancillary service aspects of resource control that drew criticism from the industry for being specific to generation when BAL-005 was originally filed with the FERC. Among other recommendations, for the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules (all similar in that they utilize real-time data from an agreed-upon common source between Adjacent BAs), the PRT recommends requirements focused on the real-time values operated to. The PRT's recommendations for BAL-005 are fully detailed below.

1) **Title**: The PRT recommends changing the title of BAL-005 to "Balancing Authority Control" to remove the implication that BAL-005 pertains exclusively to generation, and better reflect the focus on the BA acquiring necessary data to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. Based upon the input from the industry, the PRT recommends that the SDT consider whether the term AGC should be retained within any requirements. The PRT also recommends that the SDT pursue revisions to the definition of AGC as proposed below to be resource-neutral.

   AGC: Equipment that automatically adjusts ~~generation~~ resources utilized in a Balancing Authority Area from a central location to maintain the Balancing Authority's Reporting ACE within the bounds required under the NERC Reliability Standards. Resources utilized under AGC may include conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response. ~~may interchange~~

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~~schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.~~

2) **Purpose**: The SDT would also be tasked with consideration of revising the "Purpose" statement to focus on acquiring the information necessary for calculating Reporting ACE, while remaining neutral on the types of reserves or resources utilized. The PRT recommends the following revised Purpose statement for SDT consideration:

   This standard establishes requirements for acquiring necessary data for the Balancing Authority so that balancing of resources and demand can be achieved under Tie-Line Bias Control.

   Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception.

3) **Applicability**: The SDT should remove "Generator Operators", "Transmission Operators", and "Load Serving Entities" as applicable entities unless specificially added into a Standard requirement by the SDT.

4) **Requirement R1**: The PRT recommends that the content of Requirement R1 be split between what is needed for ensuring facilities are within a BA Area prior to MW being generated or consumed, and what is needed for ensuring balanced operation within an Interconnection. First, the PRT recommends that the SDT consider continuing discussions with the FAC SDT moving and restating or clarifying the TOP, LSE, and GOP requirements in a FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT discussed that the ownership of metering and other factors may drive why the LSE is included in this standard, along with other entities; however, consideration should be given to moving requirements for these facilities to be within a BA Area into a FAC standard. The PRT is concerned that removing any such requirements of the LSE, TOP, and GOP and not reflecting them within another standard may inadvertently transfer certain obligations to the BA to ensure that such loads, resources, and facilities are within the BA's metered boundaries. The SDT should explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary. Second, the PRT recommends that the SDT revise Requirements R1 and R2 to be BA requirements that all Actual Net Interchange and Scheduled Net Interchange used by the BA in its Reporting ACE

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Deleted: The SDT should remove "Generator Operators", "Transmission Operators", and "Load Serving Entities" as applicable entities unless used in the SDT's suggested revisions of this standard

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SAR Information

calculation also have an Adjacent BA, as proposed in the redlined Requirements R1 and R2. Note that the PRT does not intend with the proposed language to impose any additional requirements on the BA that currently apply to the LSE, GOP, and TOP, but also believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example) or a FAC requirement. With respect to proposed R2, the SDT should ensure that the requirement cannot be misinterpreted to imply that Dynamic Schedules can only be with physically adjacent BAs. The intent is to address adjacency in a manner consistent with the scheduling path no differently than used for interchange schedules.

5) **Requirement R2**: Retirement approved by FERC effective January 21, 2014.

6) **Requirement R3**: The PRT recommends that the SDT not use the term "Regulation Service," as in general this statement could apply to implementation of Dynamic Schedules or Pseudo-Ties, and the desire to have a common point for the data shared between the BAs implementing the Dynamic Transfer. The PRT recommends removing "adequate" and "Burden" from the requirement. The PRT recommends expanding Requirement R3 to be applicable to the implementation of tie lines, Pseudo-Ties, and Dynamic Schedules, as all require agreement between adjacent BAs on the agreed-upon points to be implemented. The PRT recommends that the SDT review the other standards such as TOP-005 to assure there is no duplication or redundancy. Specific to the concern on swapping hourly values in BAL-005 posted for industry comment. The PRT recommends deleting the proposed R3.2 and the first sentence of the proposed R3.5.2, the PRT also recommends the SDT develop a guideline document to accompany BAL-005 covering some of the suggested best practices.

7) **Requirement R4**: The PRT reviewed Requirement R4 with respect to what notification or coordination is necessary that could be considered with the other requirements in this Standard regarding Interchange. Initially the PRT was considering a recommendation that the SDT consider the requirement as it applies to Dynamic Transfer implementation as discussed in the Dynamic Transfer reliability guideline, and as it applies to the practice of implementing multiple-BA Dynamic Transfers under a process referred to as ACE Diversity Interchange. The PRT also considered recommendations to delete or modify Requirement R4 so that it requires communication with not only the BAs, but any other affected entities, and also to strike "providing Regulation Service." However, after further review, the PRT recommends retiring Requirement R4, as the basis for coordination of common values between adjacent BAs is covered in Requirement R3, and correction of information not available has also been addressed. These requirements should ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

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8) **Requirement R5**: The PRT recommends retiring Requirement R5, as the requirements placed upon the implementation of Dynamic Transfers are covered within Requirement R3. With respect to having a backup plan to the extent that a service may no longer be provided, the PRT believes this would be covered in the terms agreed to between the parties implementing the Dynamic Transfer. As proposed by the PRT, the requirements remaining in BAL-005 would ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

9) **Requirement R6**: The PRT recommends that the sentence "Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control" be captured in the definition of "Reporting ACE.". The terms used in the Requirement R6 need to be consistent with those used in Reporting ACE if the Requirement is retained. The SDT should consider whether the 30-minute requirement for RC notification is sufficient or excessive. The PRT recommends that if a timing requirement remains in the standard that it be structured in a manner to not require communication with the RC if the capability to calculate Reporting ACE is restored within the defined notification period.

10) **Requirement R7**: The PRT recommends retiring this Requirement under Paragraph 81. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, which can be done manually without any detriment to reliability. EOP-008-1 Requirement R1 recognizes that such automated capability may not be available for up to two hours for loss of control center functionality. In addition, the second sentence is not needed, as such actions would be covered under EOP-008. The PRT believes that the term "Operating AGC" in Requirement R7 refers to the capability to continuously calculate ACE (not automatic control of resources), which should be considered one of the BAs functional obligations with regard to the reliable operations and situational awareness of the BES. Though redundancy and other provisions may be in place to maintain EMS functionality, there are times when the information may not be available where the provisions under EOP-008-1 would apply.

11) **Requirement R8**: The PRT recommends that the SDT revise the Requirement with the proper context of a minimum normal scan rate and clarify how frequently all components must be factored into the Reporting ACE equation under normal operation. With respect to the sub-requirements, the SDT should ensure that any proposed revisions accommodate abnormal and emergency operations, including the possibility that the EMS or supporting telemetry may not be available, such as during an evacuation to a backup site. The PRT notes that the SDT should consider a requirement focused on a minimum scan-rate expectation under normal operations, rather than a requirement that could be interpreted as if systems have 100% availability.

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12) **Requirement R8, Part 8.1**: The BA should have visibility of system frequency within parameters consistent with EOP-008, however the PRT recommends that the requirement not be prescriptive. The SDT should review EOP-008 to ensure that this requirement is covered there. In addition, the SDT should also consider remote and redundant frequency resources to the extent that the information that is otherwise available to the BA may not be available upon loss of control center functionality. Such capability may already be anticipated under EOP-008. The SDT should consider the following questions in the development of the revised requirement: a) How much time is allowed to pass if the redundancy is lost before it must be restored? b) Does the PRT believe it is acceptable for the second and independent frequency device to be one used by another Balancing Authority? 13) **Requirement R9, Part 9.1**: The PRT recommends retiring this Requirement. The Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use. By focusing on real-time Reporting ACE, we are assuring reliability is addressed and maintained at all times. 14) **Requirement R10 and R11**: The PRT recommends retiring these requirements, as the basics of both requirements are factored into the definition of Scheduled Net Interchange used in the Reporting ACE calculation as defined in the NERC Glossary. The PRT noted that Requirement R10 is written as if "Net Scheduled Interchange" is the value used in the ACE equation; however, Net Scheduled Interchange has two meanings – the algebraic sum of all Interchange Schedules across a given path, or between Balancing Authorities for a given period or instant in time. Aside from the concern of having a definition with two different meanings, the PRT believes that neither choice in the definition accurately depicts the value inserted into the ACE or Reporting ACE, which would be the algebraic sum of all Net Scheduled Interchange with all Adjacent Balancing Authorities, including Dynamic Schedules. In addition, the PRT could not find a definition of Scheduled Interchange as used in Requirement R11. Under Section 3 below, the PRT recommends changes to certain NERC definitions.

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15) **Requirement R12**: The PRT took a holistic approach to Requirement R12 and other requirements related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, as all relate to the information exchanged between adjacent BAs. The PRT recommends a new Requirement R3 related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, where each respective Adjacent BA has agreed to common measuring points that produce an agreed-to value to be included in the calculation of Reporting ACE. The SDT should review the requirement as it relates to current practices to ensure the reliability needs are met. The PRT suggests that the holistic approach shall only be achieved if there is a comprehensive definition of ACE. Therefore, the PRT recommends the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). The PRT notes that the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary. The PRT suggests that a complete review of all the NERC Standards for use of the term "ACE" is necessary to assure that any update to the ACE definition would not impact any other Standard. 16) **Requirement R13**: The PRT suggests deleting the first sentence of R13, and suggests that the SDT include in a guideline document the practice of performing hourly error checks of the Actual Net Interchange (NI_A) operated to for the hour against an end-of-the-hour reference. The PRT also recommends a separate requirement specific to adjustments as needed to the Reporting ACE to reflect the meter error adjustment. However, the PRT is concerned that requiring correction of a component of ACE when in error (no matter how negligible) would be problematic in that not all errors require correction. The PRT recommends that the SDT consider stating the requirement in such a manner that I_{ME} is required to be zero except during times needed to compensate for any data or equipment error affecting a component of the Reporting ACE calculation (interchange or frequency). When writing the requirement, the SDT should also consider that there are other means of addressing metering corrections besides use of the I_{ME} term, which may include possible revision to real-time metering data. Uses of the I_{ME} term in the Reporting ACE may also be an appropriate subject for the guideline document the PRT is

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Similar to EOP-008-1, a holistic approach on common information and agreed to common value would eliminate duplication and potential for double jeopardy.

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recommending that the SDT develop to accompany BAL-005 covering some of the suggested best practices. **Requirement R14**: The PRT recommends that the SDT delete the first sentence in R14 and revise the second sentence to cover the minimum amount of information expected for the BA to provide in real-time to its operator. The PRT also recommends that the individual components of actual and scheduled interchange with each Adjacent Balancing Authority also be captured (Tie-Lines, Pseudo-Ties, Dynamic Schedules, block schedules as needed for coordination, and real-time schedules). Based on industry comments, the SDT should consider whether this requirement is needed in the BAL standards, whether it is adequately covered elsewhere in the standards, or whether it should be moved to the NERC Rules of Procedure for certification of the Functional Entity. 17) **Requirement R15**: The SDT should consider placing a requirement in a FAC Standard with respect to supporting infrastructure or functionality, or review EOP-008 to determine if existing requirements adequately address primary control center functionality. 18) **Requirement R16**: The PRT recommends moving the requirement for flagging bad data to revisions made in Requirement R14. 19) **Requirement R17**: The PRT recommends that this requirement be written to be specific to the equipment used to determine the frequency component required for Reporting ACE. The PRT also recommends that the SDT move any accuracy requirements applicable to the needs of the Transmission Operator, (which may include MW, MVAR, voltage, potential transformer, current transformer, and remote terminal unit or equivalent) to a TOP or FAC standard. Further study would be needed on the ".25% of full scale" and the "appropriate accuracy" language. **2. BAL-006** The BARC2 PRT has completed its review of BAL-006 and recommends that it be revised. The recommendations below include moving any requirements with implications for real-time operations into BAL-005. Among other work, the review team considered a FERC directive that recommended the development of a metric to bound the magnitude of inadvertent accumulations, as those accumulations may be indicative of a BA excessively leaning on the resources of others in its Interconnection. The review team

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consensus was that an Inadvertent Interchange accumulation value alone cannot yield useful information concerning whether a BA is operating reliably. The PRT document on the consideration of issues and directives more fully covers the PRT recommendations related to the FERC directives. The PRT's recommendations for BAL-006 are fully detailed below. 1) **Purpose**: As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this recommendation. 2) **Requirement R1**: The PRT recommends removing Requirement R1 as written and recommends that the SDT determine if there is merit in developing a reliability metric specific to this standard to measure performance to certain requirements under BAL-006, including the consideration of including the calculation of Inadvertent Interchange. In development of any metric, the PRT recommends that the SDT determine the appropriate time-frame for reliability (as close to real-time as possible). Similar to how BAL-001-2 has CPS1 and BAAL measures dependent upon the BA calculating its Reporting ACE without a stated requirement that "Each BA shall calculate its Reporting ACE", the PRT felt that if the industry supports a measure being developed that uses Inadvertent Interchange in the measure of performance, that the BA would calculate Inadvertent Interchange as needed to comply. Also, similar to the approach taken for defining Reporting ACE in the Glossary with all of the components necessary for the calculation, the PRT is recommending in Requirement R2 below that the definition of Inadvertent Interchange also be updated so that all components necessary for the calculation are identified. 3) **Requirement R2**: The PRT recommends incorporating Requirement R2 into a revised definition of Inadvertent Interchange: The PRT recommends that this definition be modified to capture that the calculation is on an hourly basis and includes the megawatt-hour values for Tie-Lines, Pseudo-Ties, and Dynamic Schedules, along with other scheduled interchange implemented under block scheduling, which does not include the effect of the ramps. The PRT recommends that the definition also include the NERC definitions of On-Peak Accounting and Off-Peak Accounting, which reference the NAESB business practice for inadvertent interchange accounting. The PRT also recommends that the definition clarify the treatment of scheduled and actual interchange associated with asynchronous ties between Interconnections. 4) **Requirement R3**: The PRT recommends incorporating Requirement R3 into BAL-005, as the requirement relates to the agreement on common values used in Real-time and also

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recommends developing a guideline to cover the practice of comparing the hourly megawatt-hour values gathered at the end of the hour against the hourly integrated values of the scan-rate data operated to, in order to determine if significant error exists. 5) **Requirement R4**: The SDT should review current practices for confirmation of interchange after-the-fact to determine and justify a shorter duration for agreement on such values for reliability purposes. The PRT also recommends that Requirement R4 be restated to require that the agreement is based upon the aggregate net schedules and net actuals by adjacent BAs as further defined in the new definition of Inadvertent Interchange. In concept, every Tie-Line, Pseudo-Tie, and Interchange Schedule (including Dynamic Schedules) implemented in the Reporting ACE calculation should have an accompanying after-the-fact megawatt-hour value accounted for in the calculation of Inadvertent Interchange. 6) **Requirement R4, Part 4.2**: The SDT should evaluate whether to retire this Requirement, as it is addressed in the new definition of Inadvertent Interchange by the proposed reference to On-Peak Accounting and Off-Peak Accounting. 7) **Requirement R4.3**: The SDT should review this requirement to determine what elements of the requirement are necessary to support reliability. The SDT also should consider including in a guideline document a practice to support providing operations personnel with information on the comparison of monthly revenue class meters to meters used for real-time operation. 8) **Requirement R5**: The SDT should review whether the practice that requires BAs to mutually agree by the 15th calendar day is needed for reliability. The PRT believes there may be merit in requiring BAs to identify the cause of the dispute, and to either correct it within a prescribed number of days, or follow a dispute resolution process. The SDT should ensure that the requirement is clear and distinct, which may require modifying or striking the language regarding dispute resolution.

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Reliability Functions		
The Reliability Standards will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.

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Reliability Functions		
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Reliability Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Reliability Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A Reliability Standard shall not give any market participant an unfair competitive advantage.	Yes.
2. A Reliability Standard shall neither mandate nor prohibit any specific market structure.	Yes.
3. A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.	Yes.

Reliability and Market Interface Principles	
4. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.	Yes.

Related Reliability Standards	
Reliability Standard No.	Explanation
BAL-001-2 and draft BAL-002-2	Some of the proposed revisions to BAL-005 focus on the components used to calculate Reporting ACE, used to measure compliance to CPS1 and BAAL in BAL-001-2, and measure compliance in the draft BAL-002-2 revisions.
EOP-008-1	The purpose of EOP-008-1 is to ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable. For certain proposed revisions to BAL-005 in this SAR, the PRT recommends that the SDT consider provisions in EOP-008-1 for the loss of control center functionality.
FAC-001-1	With respect to BAL-005 Requirement R1, the PRT recommends that the SDT consider moving and restating the TOP, LSE, and GOP requirements in an FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The PRT recommends that the SDT explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP, such that the LSE requirement may not be necessary.
Other	The PRT recommendations include that the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). As the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary, the PRT suggests that a complete review of all the NERC Standards is necessary to assure where ACE is utilized in a Standard, that any update to the ACE definition would not impact any other Standard.

Related SARs – N/A	
SAR ID	Explanation

Regional Variances – N/A	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-14.2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards Authorization Request (SAR). The electronic comment form must be completed by 8:00 p.m. ET on **August 14, 2014.**

If you have questions please contact Darrel Richardson via email or by telephone at darrel.richardson@nerc.net or 609-613-1848.

The project page may be accessed by clicking here.

Background Information

This posting is soliciting informal comment.

On September 19, 2013, the NERC Standards Committee appointed ten subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT).[1] As part of its review, the BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0.2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn.

The BARC 2 PRT recommendations for BAL-005-0.2b and BAL-006-2 were posted for a 45-day comment period from February 21, 2014 through April 7, 2014. There were 23 sets of responses, including comments from approximately 84 different people from approximately 62 companies, representing 8 of the 10 Industry Segments.

The BARC 2 PRT carefully reviewed and considered the comments received during the posting period and, based on stakeholder comments, made revisions to its recommendations. To support implementation of these recommendations, the BARC 2 PRT developed a new SAR intended to supersede the original SAR, which contains outdated information. To further support its recommendations, the BARC 2 PRT developed redlined versions of the standards. Many improvements suggested by stakeholders during the comment period were incorporated into the final recommendations and redlined standards being provided.

[1] The Standards Committee subsequently appointed an eleventh SME to the BARC 2 PRT.

The recommendations of the BARC 2 PRT are in the Periodic Review Templates and SAR. The redlined standards are posted on the project page and will be included as part of the SAR for this project. Additional documents developed to support the team's recommendations have been posted on the project page, including 1) the BARC 2 PRT's consideration of comments on the draft recommendation; 2) a list of directives and stakeholder-identified issues associated with the standards; and 3) the IERP recommendations associated with the standards, containing the BARC 2 PRT's consideration of those recommendations.

This project addresses directives in Paragraphs 406[2], 415[3], 418[4], 419[5], 428 [6] and 438[7] of FERC Order 693, and provides additional clarity to many requirements, as well as retiring requirements that meet the criteria developed in the Paragraph 81 project.

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[2] "Given that most of the commenters' concerns over the inclusion of DSM as part of regulating reserves relate to the technical requirements, the Commission clarifies that to qualify as regulating reserves, these resources must be technically capable of providing the service. In particular, all resources providing regulation must be capable of automatically responding to real-time changes in load on an equivalent basis to the response of generation equipped with automatic generation control. From the examples provided above, the Commission understands that it may be technically possible for DSM to meet equivalent requirements as conventional generators and expects the Reliability Standards development process to provide the qualifications they must meet to participate. These qualifications will be reviewed by the Commission when the revised Reliability Standard is submitted to the Commission for approval."

[3] "Both Xcel and FirstEnergy question Requirement R17 but do not oppose the Commission's proposal to approve this Reliability Standard. Earlier in this Final Rule, we direct the ERO to consider the comments received to the NOPR in its Reliability Standards development process. Thus, the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan."

[4] "The Commission adopts the NOPR proposal to require the ERO to modifiy the Reliability Standards to include a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains."

[5] "FirstEnergy has a number of suggestions to improve the existing Reliability Standard and the ERO is directed to consider those suggestions in its Reliability Standards development process."

[6] "The Commission directs the ERO to develop a modification to BAL-006-1 that adds Measures concerning the accumulation of large inadvertent imbalances and Levels of Non-Compliance. . . [W]e are concerned that large imbalances represent dependence by some balancing authorities on their neighbors and are an indication of less than desirable balancing of generation with load. The Commission also notes that the stated purpose of this Reliability Standard is to define a process for monitoring balancing authorities to ensure that, over the long term, balancing authorities do not excessively depend on other balancing authorities in the Interconnection for meeting their demand or interchange obligations."

[7] "Since the ERO indicates that the reliability aspects of this issue will be addressed in a Reliability Standards filing later this year, the Commission asks the ERO, when filing the new Reliability Standard, to explain how the new Reliability Standard satisfies the Commission's concerns."

This posting is soliciting comment on a Standard Authorization Request (SAR).

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Question

1. Do you have any specific questions or comments relating to the scope of the proposed SAR?

   ☐ Yes
   ☐ No

   Comments:

2. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here.

   ☐ Yes
   ☐ No

   Comments:

3. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

   Comments:

4. If you have any other comments on this SAR that you haven't already mentioned, please provide them here.

   Comments:

Periodic Review of BAL-005-0.2b – Automatic Generation Control and BAL-006-2 – Inadvertent Interchange (Recommendation to Revise both Standards)

May 22, 2014

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten years, or once every five years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] Project 2010-14.2 - Phase 2 of Balancing Authority Reliability-based Controls (BARC 2) was included in the current cycle of periodic reviews.

The NERC Standards Committee appointed ten industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) on September 19, 2013.[2] The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0_2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn.

As a result of that examination, the BARC 2 PRT recommends to **REVISE** BAL-005-0_2b and BAL-006-2, and has therefore developed a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revisions. **The purpose of all documents contained in this posting is to elicit feedback from industry on the BARC 2 PRT's recommendations.**

Applicable Reliability Standards: BAL-005-0.2b and BAL-006-2 **Note:** BAL-005-0 was filed for FERC approval on April 4, 2006 in Docket No. RM06-16-000 and was approved on March 16, 2007 in Order No. 693.6. Also, FERC accepted an errata filing to BAL-005-0.1b on September 13, 2012, which replaced Appendix 1 with a corrected version of a FERC-approved interpretation, and made an internal reference

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] The Standards Committee subsequently appointed Scott Brooks of Manitoba Hydro to the BARC 2 PRT.

correction in the interpretation, thus resulting in BAL-005-0.2b. On March 16, 2007 FERC issued Order Number 693 approving Reliability Standard BAL-006-1. BAL-006-2, which removed the MISO waivers found in BAL-006-1, was approved by FERC on January 6, 2011 in Docket No. RD10-04-000.
Team Members (include name and organization): 1. Doug Hils, Duke Energy (Chair) 2. Thomas W. (Tom) Siegrist, Brickfield Burchette Ritts and Stone, PC (Vice Chair) 3. Scott Brooks, Manitoba Hydro 4. Ron Carlsen, Southern Company 5. Howard F. Illian, Energy Mark, Inc. 6. Mike Potishnak, Representing NPCC 7. Jerry Rust, Northwest Power Pool 8. Robert Staton, Xcel Energy 9. Glenn Stephens, Santee Cooper 10. Stephen Swan, MISO 11. Mark Trumble, Omaha Public Power District
Date Review Completed: February 14, 2014

Background Information *(initially completed by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standards? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

   Please see the attached *Consideration of Issues and Directives*.

2. Have stakeholders requested clarity on the Reliability Standards in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes (See BAL-005-0.2b, Appendix 1 - Interpretation of Requirement R17)

   ☐ No

3. Are the Reliability Standards one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Do the Reliability Standards need to be modified or converted to the results-based standard (RBS) format as outlined in *Attachment 1: Results-Based Standards*? Note that this analysis is twofold and requires collaboration among NERC staff and the Review Team. First, determine whether the *substance* of the Reliability Standard comports to the RBS principles described in Attachment 1. Second, ensure that, as Reliability Standards are reviewed, the *formatting* is changed as necessary to comply with the current format of a Reliability Standard. If the answer to either part of this question is "Yes," the standard should be revised.

   ☒ Yes

☐ No

Note: The BARC 2 PRT reviewed BAL-005-0.2b and BAL-006-2 and determined that many of the requirements were similar in nature and could be simplified to provide a clear and measurable expected outcome, such as: (1) a stated level of reliability performance; (2) a reduction in a specified reliability risk; or (3) a necessary competency.

Additional Questions Considered by the BARC 2 PRT

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any: The BARC 2 PRT applied the criteria specified in *Attachment 2: Paragraph 81 Criteria* in reviewing BAL-005 and BAL-006. As that document more fully explains, for a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both an overarching criterion, specifically, whether the requirement does little, if anything, to benefit or protect the reliable operation of the Bulk Electric System (BES), and at least one other criterion specified therein. The PRT concluded that eight requirements should be retired under Paragraph 81 concepts as detailed in Table 1:

Table 1 - PRT Recommended Paragraph 81 Retirements

Requirement	Rationale
BAL-005, Requirement R4	The basis for coordination of common values between adjacent BAs is covered in Requirement R3, and correction of information not available has also been addressed. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-005, Requirement R5	The requirements placed upon the implementation of Dynamic Transfers are covered within Requirement R3. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-005, Requirement R7	The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, which can be done manually without any detriment to reliability. EOP-008-1 Requirement R1 recognizes that such automated capability may not be available for up to two hours for loss of control center functionality. In addition, the second sentence is not needed, as such actions would be covered under EOP-008. The PRT believes that the term "Operating AGC" in Requirement R7 refers to the

	capability to continuously calculate ACE (not automatic control of resources), which should be considered one of the BAs functional obligations with regard to the reliable operations and situational awareness of the BES. Though redundancy and other provisions may be in place to maintain EMS functionality, there are times when the information may not be available where the provisions under EOP-008-1 would apply. In light of these unnecessary redundancies, this requirement does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-005, Requirement R9, Part 9.1	The Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use. By focusing on real-time Reporting ACE, we are assuring reliability is addressed and maintained at all times. Because the Reporting ACE addresses the reliability concerns originally contemplated in this requirement, the requirement is needlessly redundant and does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-005, Requirement R10	The definition of Reporting ACE includes the provision that Scheduled Net Interchange (NIs) used in the Reporting ACE calculation include Dynamic Schedules. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-005, Requirement R11	The definition of Reporting ACE includes the provision that the effect of schedule ramps be included in the value Scheduled Net Interchange (NIs) used in the Reporting ACE calculation. Therefore, this requirement is redundant and does little, if anything, to benefit or protect the reliable operation of the BES.
BAL-006, Requirement R1	Requirement R1 is written only as an energy accounting requirement. The Requirement is administrative in nature and does little, if anything to benefit or protect the reliable operation of the BES. However, the SDT should determine if there is merit in developing a reliability metric specific to this standard including the calculation of Inadvertent Interchange in a reliability metric to measure performance to certain requirements under BAL-0065, where the SDT may consider including the calculation of Inadvertent Interchange.
BAL-006, Requirement R2	Requirement R2 is written only as an energy accounting requirement. The Requirement is administrative in nature and does little, if anything to benefit or protect the reliable operation of the BES. However, the PRT recommends that the SDT incorporate Requirement R2 into a revised definition of Inadvertent Interchange.

The BARC 2 PRT carefully considered each recommendation made in the Independent Expert Review Report (IERR) as detailed in Table 2 below. Based on the BARC 2 PRT's discussions and expertise on the matter, including some having been involved in the development and revisions to NERC Policy 1 used as the basis for the NERC BAL Standards, the BARC 2 PRT determined that the balance of the requirements recommended for retirement by the Independent Expert Review Report are necessary to retain in some form for reliability:

Table 2 - PRT Consideration of IERR Recommendations

Requirement	**IERR Recommendation**	**PRT Response**
BAL-005, Requirement R2	Retire, P81. Phase 1	Requirement removed under Paragraph 81 Phase 1.
BAL-005, Requirement R3	Retire, P81. Duplicative of R1.	The PRT **disagreed** with the IERR, as the intent of Requirement R1 is to ensure that all load, resources and transmission facilities are accounted for within the BAs in an Interconnection, whereas Requirement R3 was intended to cover the metering communications, etc., when load or resources may be Dynamically Transferred. The PRT recommendations include treating the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules in a similar manner, as all require agreement on the common information that will be used between the Adjacent BAs and the implementation of dynamically changing data in the Reporting ACE. The PRT recommends that the SDT not use the term "Regulation Service," as in general this statement could apply to implementation of Dynamic Schedules or Pseudo-Ties, and the desire to have a common point for the data shared between the BAs implementing the Dynamic Transfer. Entities must have a process in place to always have common and agreed-upon information even when primary facilities are not available. The PRT recommends removing "adequate" and "Burden" from the requirement.

BAL-005, Requirement R8	Retire, P81. Outdated due to technology.	The PRT **disagreed** with the IERR, as Requirement R8 establishes the minimum expectation of how often ACE must be calculated by all Balancing Authorities. However, as written, Requirement R8 provides no provisions for abnormal or emergency operations when the automated calculation of ACE may not be available. The PRT recommendations include that the SDT revise the Requirement with the proper context of a minimum normal scan rate and clarify how frequently all components must be factored into the Reporting ACE equation under normal operation. With respect to the sub-requirements, the SDT should ensure that any proposed revisions accommodate abnormal and emergency operations, including the possibility that the EMS or supporting telemetry may not be available, such as during an evacuation to a backup site. The PRT notes that the SDT should consider a requirement focused on a minimum scan-rate expectation under normal operations, rather than a requirement that could be interpreted as if systems have 100% availability.
BAL-005, Requirement R9	Retire, P81. This is a definition not a requirement.	The PRT **agreed** with the IERR to retire Requirement R9, as the Interchange values are included the definition of Reporting ACE.
BAL-005, Requirement R10	Retire, P81. This is a definition not a requirement.	The PRT **agreed** with the IERR as the definition of Reporting ACE includes the provision that Scheduled Net Interchange (NIs) used in the Reporting ACE calculation include Dynamic Schedules.
BAL-005, Requirement R11	Retire, P81. This is a business practice and is automated in most EMS software.	The PRT **agreed** with the IERR, as the definition of Reporting ACE includes the provision that the effect of schedule ramps be included in the value Scheduled Net Interchange (NIs) used in the Reporting ACE calculation.
BAL-005, Requirement R12	Retire, P81. This in the ACE equation so does not need to be repeated.	The PRT **agreed** with the IERR to retire Requirement R12 as written. However, the intent of certain sub requirements still needs to be captured and written as applicable to Tie-Line, Pseudo-Ties and Dynamic Schedules. The PRT recommends a new requirement where each respective Adjacent BAalancing Authority has agreed to common

		measuring points that produce an agreed-to common value to be included in the calculation of Reporting ACE. Accuracy and review of the agreed-to common value is reflected in the new requirement requiring comparison of hourly megawatt-hour values against the integrated data operated to for Tie-Lines, Dynamic Schedules, and Pseudo-Ties. The SDT should review the requirement as it relates to current practices to ensure the reliability needs are met.
BAL-005, Requirement R13	Retire, P81. This is after the fact and is automated in most EMS software.	The PRT **disagreed** with the IERR on some aspects of R13. The PRT suggests deleting the first sentence of R13, and suggests that the SDT include in a guideline document the practice of performing hourly error checks of the NIA operated to for the hour against an end-of-the-hour reference. The PRT also recommends a separate requirement specific to adjustments as needed to the Reporting ACE to reflect the meter error adjustment. However, the PRT is concerned that requiring correction of a component of ACE when in error (no matter how negligible) would be problematic in that not all errors require correction. The PRT recommends that the SDT consider stating the requirement in such a manner that I_{ME} is required to be zero except during times needed to compensate for any data or equipment error affecting a component of the Reporting ACE calculation (Interchange or frequency). The SDT should also allow in this requirement for other means of addressing metering corrections, which may include possible revision to real-time metering data. Uses of the I_{ME} term in the Reporting ACE may also be an appropriate subject for the guideline document the PRT is recommending that the SDT develop to accompany BAL-005 covering some of the suggested best practices.

BAL-005, Requirement R16	Retire, This is a guide for the quality of the EMS system. Provide to the 2009-02 team for consideration.	The PRT **agreed** with the IERR to retire Requirement R16 contingent upon addressing one provision. The PRT recommends moving the requirement for flagging bad data to revisions made in Requirement R14.
BAL-006, Requirement R1	Retire. This is only for energy accounting. Covered by tagging requirements	The PRT **agreed** with the IERR that R1 is an energy accounting requirement and should be retired; however, the PRT recommends that the SDT determine if there is merit in developing a reliability metric specific to this standard to measure performance to certain requirements under BAL-006, where the SDT may consider including the calculation of Inadvertent Interchange. In development of any metric, the PRT recommends that the SDT determine the appropriate time-frame for reliability (as close to real-time as possible). Similar to how BAL-001-2 has CPS1 and BAAL measures dependent upon the BA calculating its Reporting ACE without a stated requirement that "Each BA shall calculate its Reporting ACE", the PRT felt that if the industry supports a measure being developed that uses Inadvertent Interchange in the measure of performance, that the BA would calculate Inadvertent Interchange as needed to comply. Also, similar to the approach taken for defining Reporting ACE in the Glossary with all of the components necessary for the calculation, the PRT is recommending in Requirement R2 below that the definition of Inadvertent Interchange also be updated so that all components necessary for the calculation are identified.
BAL-006, Requirement R2	Retire. This is only for energy accounting. Covered by tagging requirements.	The PRT **agreed** with the IERR that R2 is an energy accounting requirement and recommends retirement contingent upon the SDT incorporating Requirement R2 into a revised definition of Inadvertent Interchange. The PRT recommends that this definition be modified to capture that the calculation is on an hourly basis and includes the megawatt-hour values for Tie-Lines, Pseudo-Ties, and Dynamic Schedules, along with other scheduled

		interchange implemented under block scheduling, which does not include the effect of the ramps. The PRT recommends that the definition also include the NERC definitions of On-Peak Accounting and Off-Peak Accounting, which reference the NAESB business practice for inadvertent interchange accounting. The PRT also recommends that the definition clarify the treatment of scheduled and actual interchange associated with asynchronous ties between Interconnections.
BAL-006, Requirement R3	Retire. This is only for energy accounting. Covered by tagging requirements (automated).	The PRT **disagreed** with the IERR but recommends incorporating Requirement R3 into BAL-005, as the requirement relates to the agreement on common values used in Real-time and also recommends developing a guideline to cover the practice of comparing the hourly megawatt-hour values gathered at the end of the hour against the hourly integrated values of the scan-rate data operated to, in order to determine if significant error exists.
BAL-006, Requirement R4	Retire. This is only for energy accounting. Covered by tagging requirements (automated).	The PRT **disagreed** with the IERR, as it is important to reliability that Adjacent Balancing Authorities agree on the scheduled and actual Interchange between them on a timely basis as a means to detect when errors may exist so that they can be corrected in operations. The PRT recommends that the SDT review current practices for confirmation for interchange after-the-fact to determine and justify a shorter duration for agreement on such values for reliability purposes. The PRT also recommends that Requirement R4 be restated to require that the agreement is based upon the aggregate net schedules and net actuals by adjacent BAs as further defined in the new definition of Inadvertent Interchange. In concept, every Tie-Line, Pseudo-Tie, and Interchange Schedule (including Dynamic Schedules), implemented in the Reporting ACE calculation should have an accompanying after-the-fact megawatt-hour value accounted for in the calculation of Inadvertent Interchange. Requirement R4 Part 4.2 might be addressed in the

		new definition of Inadvertent Interchange by the proposed reference to On-Peak Accounting and Off-Peak Accounting. The SDT should review this requirement to determine what elements of the requirement are necessary to support reliability. The SDT also should consider including in a guideline document a practice to support providing operations personnel with information on the comparison of monthly revenue class meters to meters used for real-time operation.
BAL-006, Requirement R5	Retire. This is only for energy accounting. Covered by tagging requirements (automated).	The PRT **could not agree** with the IERR without investigation by the SDT. The SDT should review whether the practice that requires BAs to mutually agree by the 15th calendar day is needed for reliability. The PRT believes there may be merit in requiring BAs to identify the cause of the dispute, and to either correct it within a prescribed number of days, or follow a dispute resolution process. The SDT should ensure that the requirement is clear and distinct, which may require modifying or striking the language regarding dispute resolution.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

☒ Yes

☐ No

Please summarize your assessment: The BARC 2 PRT recommends the development of a reference document to clarify the requirements in BAL-005 and BAL-006, and recommends revising the following sections of BAL-005 and BAL-006 to improve clarity of the standards:

BAL-005

The BARC2 PRT has completed its review of BAL-005, and among other recommendations, proposes certain revisions below which would remove references to the types of resources and reserves utilized by the Balancing Authority to balance resources and demand. The PRT recommendations focus on the components that make up the Reporting ACE, and not on the ancillary service aspects of resource control that drew criticism from the industry for being specific to generation when BAL-005 was originally filed with the FERC. Among other recommendations, for the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules (all similar in that they utilize real-time data from an agreed-upon common source between Adjacent BAs), the PRT recommends requirements focused on the real-time values operated to. The PRT recommendations for BAL-005 are:

1) **Title**: The PRT recommends changing the title of BAL-005 to "Balancing Authority Control" to remove the implication that BAL-005 pertains exclusively to generation, and better reflect the focus on the BA acquiring necessary data to calculate Reporting ACE so that balancing of resources and demand can be achieved under Tie-Line Bias Control. Based upon the input from the industry, the PRT recommends that the SDT consider whether the term AGC should be retained within any requirements. The PRT also recommends that the SDT pursue revisions to the definition of AGC as proposed below to be resource-neutral.

   AGC: Equipment that automatically adjusts ~~generation~~ resources utilized in a Balancing Authority Area from a central location to maintain the Balancing Authority's Reporting ACE within the bounds required under the NERC Reliability Standards. Resources utilized under AGC may include conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response. ~~may interchange schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~

2) **Purpose**: The Standards Drafting Team (SDT) tasked with implementing the SAR developed by the PRT should consider revising the "Purpose" statement to focus on acquiring the information necessary for calculating Reporting ACE, while remaining neutral on the types of reserves or resources utilized. The PRT recommends the following for SDT consideration:

   > This standard establishes requirements for acquiring necessary data for the Balancing Authority so that balancing of resources and demand can be achieved under Tie-Line Bias Control

The PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception.

3) **Applicability**: The SDT should remove “Generator Operators”, “Transmission Operators”, and “Load Serving Entities” as applicable entities unless used in the SDT’s suggested revisions of this standard. For example, the SDT discussed that the ownership of metering and other factors may drive why the LSE is included in this standard, along with other entities, however consideration should be given to moving requirements for facilities to be within a BA Area to a FAC standard. The PRT is concerned that removing any requirements of the LSE, TOP, and GOP and not reflecting them within another standard may inadvertently transfer certain obligations to the BA to ensure that such loads, resources, and facilities are within their metered boundaries. The SDT should ensure that any suggested revisions address this concern and should also consider placing a comparable requirement in a FAC Standard.

4) **Requirement R1**: The PRT recommends that the content of Requirement R1 be split between what is needed for ensuring facilities are within a BA Area prior to MW being generated or consumed, and what is needed for ensuring balanced operation within an Interconnection. First, the PRT recommends that the SDT consider continuing discussions with the FAC SDT on moving and restating or clarifying the TOP, LSE, and GOP requirements in a FAC Standard to ensure facilities are within the metered boundaries of a BA prior to transmission operation, resource operation, or load being served. The SDT should explore whether the role of the TOP would appropriately cover the loads interconnected to that TOP such that the LSE requirement may not be necessary. Second, the PRT recommends that the SDT revise Requirements R1 and R2 to be BA requirements that all Actual Net Interchange and Scheduled Net Interchange used by the BA in its Reporting ACE calculation, have an Adjacent BA, as proposed in the redlined Requirements R1 and R2. Note that the PRT does not intend the proposed language to impose any additional requirements on the BA that currently apply to the LSE, GOP, and TOP, but believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements or a FAC requirement. With respect to proposed Requirement R2, the SDT should ensure that the requirement cannot be misinterpreted to imply that Dynamic Schedules can only be with physically adjacent BAs. The intent is to address adjacency in a manner consistent with the scheduling path no differently than used for interchange schedules.

5) **Requirement R2**: Retirement approved by FERC effective January 21, 2014.

6) **Requirement R3**: The PRT recommends that the SDT not use the term “Regulation Service,” as in general this statement could apply to implementation of Dynamic Schedules or Pseudo-Ties, and the desire to have a common point for the data shared between the BAs implementing the Dynamic Transfer. The PRT recommends removing “adequate” and “Burden” from the

requirement. The PRT recommends expanding Requirement R3 to be applicable to the implementation of tie lines, Pseudo-Ties, and Dynamic Schedules, as all require agreement between adjacent BAs on the agreed-upon points to be implemented. The PRT recommends that the SDT review the other standards such as TOP-005 to assure there is no duplication or redundancy. Specific to the concern on swapping hourly values in BAL-005, the PRT recommends deleting the proposed R3.2 and the first sentence of the proposed R3.5.2, the PRT also recommends the SDT develop a guideline document to accompany BAL-005 covering some of the suggested best practices.

7) **Requirement R4**: The PRT reviewed Requirement R4 with respect to what notification or coordination is necessary that could be considered with the other requirements around Interchange. Initially the PRT was considering a recommendation that the SDT consider the requirement as it applies to Dynamic Transfer implementation as discussed in the Dynamic Transfer reliability guideline, and as it applies to the practice of implementing multiple-BA Dynamic Transfers under a process referred to as ACE Diversity Interchange. The PRT also considered recommendations to delete or modify Requirement R4 so that it requires communication with not only the BAs but any other affected entities, and to strike "providing Regulation Service." However, after further review, the PRT recommends retiring Requirement R4, as the basis for coordination of common values between adjacent BAs is covered in Requirement R3, and correction of information not available has also been addressed. These requirements should ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

8) **Requirement R5**: The PRT recommends retiring Requirement R5, as the requirements placed upon the implementation of Dynamic Transfers are covered within Requirement R3. With respect to having a backup plan to the extent that a service may no longer be provided, the PRT believes this would be in the terms of the business arrangement. As proposed by the PRT, the requirements remaining in BAL-005 would ensure that any failure to perform would be reflected in the BA performance under BAL-001-2.

9) **Requirement R6**: The PRT recommends that the sentence "Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control" be captured in the definition of "Reporting ACE.". The terms used in the Requirement R6 need to be consistent with those used in Reporting ACE if the Requirement is retained. The SDT should consider whether the 30-minute requirement for RC notification is sufficient or excessive. The PRT recommends that if a timing requirement remains in the standard that it be structured in a manner to not require communication with the RC if the capability to calculate Reporting ACE is restored within the defined notification period.

10) **Requirement R7**: The PRT recommends retiring this Requirement under Paragraph 81. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, which can be done manually without any detriment to reliability. EOP-008-1 Requirement R1 recognizes that such automated capability may not be available for up to two hours for loss of control center functionality. In addition, the second sentence is not needed, as such actions would be covered under EOP-008. The PRT believes that the term "Operating AGC" in Requirement R7 refers to the capability to continuously calculate ACE (not automatic control of resources), which should be considered one of the BAs functional obligations with regard to the reliable operations and situational awareness of the BES. Though redundancy and other provisions may be in place to maintain EMS functionality, there are times when the information may not be available where the provisions under EOP-008-1 would apply.

11) **Requirement R8**: The PRT recommends that the SDT revise the Requirement with the proper context of a minimum normal scan rate and clarify how frequently all components must be factored into the Reporting ACE equation under normal operation. With respect to the sub-requirements, the SDT should ensure that any proposed revisions accommodate abnormal and emergency operations, including the possibility that the EMS or supporting telemetry may not be available, such as during an evacuation to a backup site. The PRT notes that the SDT should consider a requirement focused on a minimum scan-rate expectation under normal operations, rather than a requirement that could be interpreted as if systems have 100% availability.

12) **Requirement R8, Part 8.1**: The BA should have visibility of system frequency within parameters consistent with EOP-008, however the PRT recommends that the requirement not be prescriptive. The SDT should review EOP-008 to ensure the intent of this requirement is covered there, and to ensure consistency among the standards. In addition, the SDT should also consider remote and redundant frequency resources to the extent that the information otherwise available to the BA may not be available upon loss of control center functionality. Such capability may already be anticipated under EOP-008. The SDT should consider the following questions in the development of the revised requirement:

    a) How much time is allowed to pass if the redundancy is lost before it must be restored?

    b) Does the PRT believe it is acceptable for the second and independent frequency device to be one used by another Balancing Authority?

13) **Requirement R9, Part 9.1**: The PRT recommends retiring this Requirement. The Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the

Balancing Authority is not being instructed “how” to implement the HVDC link, but allowed to decide the method it will use. By focusing on real-time Reporting ACE, we are assuring reliability is addressed and maintained at all times. The PRT suggests that the Balancing Authority during an audit may be asked to provide evidence that its HVDC link was included or was not included in Reporting ACE under the provisions allowed by definition.

14) **Requirements R10 and R11**: The PRT recommends the retirement of these requirements, as the basics of both requirements are factored into the definition of Scheduled Net Interchange (NIs) used in the Reporting ACE calculation as defined in the NERC Glossary.

    The PRT noted that Requirement R10 is written as if “Net Scheduled Interchange” is the value used in the ACE equation; however, Net Scheduled Interchange has two meanings – the algebraic sum of all Interchange Schedules across a given path, or between Balancing Authorities for a given period or instant in time. Aside from the concern of having a definition with two different meanings, the PRT believes that neither choice in the definition accurately depicts the value inserted into the ACE or Reporting ACE, which would be the algebraic sum of all Net Scheduled Interchange with all Adjacent Balancing Authorities, including Dynamic Schedules. In addition, the PRT could not find a definition of Scheduled Interchange as used in Requirement R11. Under Section 3 below, the PRT recommends changes to certain NERC definitions.

15) **Requirement R12**: The PRT took a holistic approach to Requirement R12 and other requirements related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, as all relate to the information exchanged between adjacent BAs.

    The PRT recommends a new Requirement R3 related to the implementation of Tie-Lines, Pseudo-Ties, and Dynamic Schedules, where each respective Adjacent BA has agreed to common measuring points that produce an agreed-to value to be included in the calculation of Reporting ACE. The SDT should review the requirement as it relates to current practices to ensure the reliability needs are met.

    The PRT suggests that the holistic approach shall only be achieved if there is a comprehensive definition of ACE. Therefore the PRT recommends the ACE and Reporting ACE definitions be reviewed (understanding and identifying as well why there is a difference) to assure that they are comprehensive (including items such as all AC Tie-Lines, Pseudo-ties, and all other necessary Adjacent BA information). As the comprehensive details of the ACE calculation in BAL-001-1 will be retired upon implementation of BAL-001-2, where ACE will only be defined in the NERC Glossary, the PRT suggests that a complete review of all the NERC Standards is necessary to assure where ACE is utilized in a Standard, that any update to the ACE definition would not impact any other Standard.

16) **Requirement R13**: The PRT suggests deleting the first sentence of R13, and suggests that the SDT include in a guideline document the practice of performing hourly error checks of the NI_A operated to for the hour against an end-of-the-hour reference.

The PRT also recommends a separate requirement specific to adjustments as needed to the Reporting ACE to reflect the meter error adjustment. However, the PRT is concerned that requiring correction of a component of ACE when in error (no matter how negligible) would be problematic in that not all errors require correction. The PRT recommends that the SDT consider stating the requirement in such a manner that I_{ME} is required to be zero except during times needed to compensate for any data or equipment error affecting a component of the Reporting ACE calculation (Interchange or frequency). The SDT should also allow in this requirement for other means of addressing metering corrections, which may include possible revision to real-time metering data. Uses of the I_{ME} term in the Reporting ACE may also be an appropriate subject for the guideline document the PRT is recommending that the SDT develop to accompany BAL-005 covering some of the suggested best practices.

17) **Requirement R14**: The PRT recommends that the SDT delete the first sentence in R14 and revise the second sentence to cover the minimum amount of information expected for the BA to provide in real-time to its operatormade the recommendation reflected in the proposed redline to define minimum expectations for situational awareness of the BES. The PRT also recommends that the individual components of actual and scheduled interchange with each Adjacent Balancing Authority also be captured (Tie-Lines, Pseudo-Ties, Dynamic Schedules, block schedules as needed for coordination, and real-time schedules). Based on industry comments, the SDT should consider whether this requirement is needed in the BAL standards, whether it is adequately covered elsewhere in the standards, or whether it should be moved to the NERC Rules of Procedure for certification of the Functional Entity.

18) **Requirement R15**: The SDT should consider continued coordination with the Project 2010-02 FAC SDT on potentially placing a requirement in FAC with respect to supporting infrastructure or functionality, or review EOP-008 to determine if existing requirements adequately address primary control center functionality.

19) **Requirement R16**: The PRT recommends moving the requirement for flagging bad data to revisions made in Requirement R14.

20) **Requirement R17**: The PRT recommends that this requirement be written to be specific to the equipment used to determine the frequency component required for Reporting ACE. The PRT also recommends that the SDT recommend moving any accuracy requirements applicable to the needs of the Transmission Operator, which may include MW, MVAR, voltage, potential

transformer, current transformer, and remote terminal unit or equivalent to a TOP or FAC standard. Further study would be needed on the “.25% of full scale” and the “appropriate accuracy” language.

BAL-006

The BARC2 PRT has completed its review of BAL-006 and recommends that it be revised. The recommendations below include moving any requirements with implications to real-time operations into BAL-005.

Among other work, the review team considered a FERC directive that recommended the development of a metric to bound the magnitude of inadvertent accumulations, as those accumulations may be indicative of a Balancing Authority excessively leaning on the resources of others in its Interconnection. The review team consensus was that an Inadvertent Interchange accumulation value alone cannot yield useful information concerning whether a Balancing Authority is operating reliably. The PRT document on the consideration of issues and directives more fully covers the PRT recommendations related to the FERC directives. The PRT recommendations for BAL-006 are:

1) **Purpose**: As the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this recommendation.

2) **Requirement R1**: The PRT recommends removing Requirement R1 as written and recommends that the SDT determine if there is merit in developing a reliability metric specific to this standard including the calculation of Inadvertent Interchange in a reliability metric to measure performance to certain requirements under BAL-0065, where the SDT may consider including the calculation of Inadvertent Interchange. In development of any metric, the PRT recommends that the SDT determine the appropriate time-frame for reliability (as close to real-time as possible). Similar to how BAL-001-2 has CPS1 and BAAL measures dependent upon the BA calculating its Reporting ACE without a stated requirement that "Each BA shall calculate its Reporting ACE", the PRT felt that if the industry supports a measure being developed that uses Inadvertent Interchange in the measure of performance, that the BA would calculate Inadvertent Interchange as needed to comply. Also, similar to the approach taken for defining Reporting ACE in the Glossary with all of the components necessary for the calculation, the PRT is recommending in Requirement R2 below that the definition of Inadvertent Interchange also be updated so that all components necessary for the calculation are identified.

3) **Requirement R2**: The PRT recommends incorporating R2 into a revised definition of Inadvertent Interchange: The PRT recommends that this definition be modified to capture that the calculation is on an hourly basis and includes the megawatt-hour values for Tie-Lines, Pseudo-Ties, and Dynamic Schedules, along with other scheduled interchange implemented under block scheduling, which does not include the effect of the ramps. The PRT recommends

that the definition also include the NERC definitions of On-Peak Accounting and Off-Peak Accounting, which reference the NAESB business practice for inadvertent interchange accounting. The PRT also recommends that the definition clarify the treatment of scheduled and actual interchange associated with asynchronous ties between Interconnections.

4) **Requirement R3**: The PRT recommends incorporating Requirement R3 into BAL-005, as the requirement relates to the agreement on common values used in Real-time and also recommends developing a guideline to cover the practice of comparing the hourly megawatt-hour values gathered at the end of the hour against the hourly integrated values of the scan-rate data operated to, in order to determine if significant error exists.

5) **Requirement R4**: With respect to Requirement R4, the SDT should review current practices for confirmation for interchange after-the-fact to determine and justify a shorter duration for agreement on such values for reliability purposes. The PRT also recommends that Requirement R4 be restated to require that the agreement is based upon the aggregate net schedules and net actuals by adjacent BAs as further defined in the new definition of Inadvertent Interchange. In concept, every Tie-Line, Pseudo-Tie, and Interchange Schedule (including Dynamic Schedules), implemented in the Reporting ACE calculation should have an accompanying after-the-fact megawatt-hour value accounted for in the calculation of Inadvertent Interchange.

6) **Requirement R4, Part 4.2:** The SDT should evaluate whether this requirement is addressed in the new definition of Inadvertent Interchange by the proposed reference to On-Peak Accounting and Off-Peak Accounting.

7) **Requirement R4, Part 4.3**: The SDT should review this requirement to determine what elements of the requirement are necessary to support reliability. The SDT also should consider including in a guideline document a practice to support providing operations personnel with information on the comparison of monthly revenue class meters to meters used for real-time operation.

8) **Requirement R5**: The SDT should review whether the practice that requires BAs to mutually agree by the 15th calendar day is needed for reliability. The PRT believes there may be merit in requiring BAs to identify the cause of the dispute, and to either correct it within a prescribed number of days, or follow a dispute resolution process. The SDT should ensure that the requirement is clear and distinct, which may require modifying or striking the language regarding dispute resolution.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain: The SDT should review definitions for consistency on Scheduled Interchange and clarification of Pseudo-Tie to indicate that it is treated no differently than tie line metering for a common point between two BAs, communication requirements, etc., and included in the calculation of Actual Net Interchange and the Reporting ACE equation. The SDT should also review proposed changes to the INT standards as part of this examination.

The use of multiple Interchange terms within the Standards prompted the PRT to reference the Glossary of Terms Used in NERC Reliability Standards. The PRT reviewed the definitions of Actual Net Interchange and Scheduled Net Interchange used within the definition of Reporting ACE, along with the definitions of Interchange Schedule, Net Interchange Schedule, Net Scheduled Interchange, and Net Actual Interchange. The PRT found it confusing to have multiple interchange definitions with similar titles, and some with similar meanings, and recommends the SDT consider the following:

a) Scan all of the NERC Standards, all terms in BAL-005 and -006, and the NERC Glossary to determine if the terms associated with the subject standards are used or defined appropriately (e.g., NI_S, NI_A, I_S, I_A, ACE, and Reporting ACE).
b) Ensure that any suggested revisions to scheduled interchange definitions retain the overall concepts that:
- the schedule ramps must be reflected in the Reporting ACE;
- the static schedules (any that are not Dynamic Schedules) coordinated between Adjacent BAs prior to implementation use block accounting ignoring the schedule ramps;
- the estimated MW values of the Dynamic Schedules prior to implementation are typically not included in the scheduled interchange values coordinated and agreed to between Adjacent BAs; and
- the megawatt-hour values of scheduled interchange agreed-to after the fact reflect the static schedules (any that are not Dynamic Schedules) operated to using block accounting integrated over the hour but ignoring the ramps, plus the hourly integrated values for any Dynamic Schedules.

Suggested Revisions to NERC Glossary Definitions:

Automatic Generation Control (“AGC”)
Equipment that automatically adjusts ~~generation~~ **resources** utilized in a Balancing Authority Area from a central location to maintain the Balancing Authority’s ACE within the bounds required under the NERC Reliability Standards**. Resources utilized under AGC may include conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response**. ~~may interchange schedule plus~~

~~Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~

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 **Actual Net Interchange** and its **Scheduled Net 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 Pseudo-Ties ***with all Adjacent Balancing Authorities, which may use anti-aliasing filters as needed to more accurately represent the actual interchange as determined by the Adjacent Balancing Authorities.*** Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude ***the actual*** megawatt transfers on those Tie lines in ***the calculation of NI_A***, provided they are implemented in the same manner for ***Scheduled Net Interchange***.

NI_S (Scheduled Net Interchange) is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with ***all*** **A**djacent 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 ***the scheduled*** megawatt transfers on those Tie Lines in the ***calculation of NI_S***, provided they are implemented in the same manner for ***Actual Net Interchange***.

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***-error*** 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~~ ***Actual Net Interchange*** (NI_A) and the cumulative hourly net Interchange energy measurement (in megawatt-hours).

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), and Violation Severity Levels (VSL)) consistent with the

direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☐ Yes

☒ No

The standard drafting team will address compliance elements.

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☒ Yes

   ☐ No

   As noted above, the PRT recommends a thorough review of all of the NERC Standards, all terms in BAL-005 and -006, and the NERC Glossary to determine if the Interchange-related terms associated with the subject standards are used or defined appropriately. For example, the PRT noted that BAL-005 R10 is written as if "Net Scheduled Interchange" is the value used in the ACE equation; however, Net Scheduled Interchange has two meanings – the algebraic sum of all Interchange Schedules across a given path, or between Balancing Authorities for a given period or instant in time. Also, the PRT could not find a definition of Scheduled Interchange as used in BAL-005 R11.

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

As indicated in the detail provided for BAL-005 R1, the PRT proposes that the GOP requirement to have its resource facilities within the metered boundaries of a BA be moved to an FAC requirement as no MWs should be generated prior to such arrangements.

Recommendation

The answers to the questions above, along with a preliminary recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM

☒ REVISE

☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See the attached draft SAR.

Preliminary Recommendation posted for industry comment (date): February 21, 2014

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☐ REVISE

☐ RETIRE

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff and the Review Team asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff and the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[3] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[3] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Unofficial Nomination Form

Project 2010-14.2 Balancing Authority Reliability-based Control Standard Drafting Team

Please return this form as soon as possible. If you have any questions, please contact Darrel Richardson at darrel.richardson@nerc.net.

By submitting the following information, you are indicating your willingness and agreement to actively participate in the Standard Drafting Team (SDT) meetings if appointed to the SDT by the Standards Committee. This means that if you are appointed to the SDT, you are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings as well as participate in all the SDT meetings held via conference calls, and failure to do so shall result in your removal from the SDT.

Project 2010-14.2 Balancing Authority Reliability-based Control

Project 2010-14.2 focuses on implementing the recommendations from the five year review team and closing out Directives from FERC Order 693. The standards involved are:

- BAL-005-0.2b – Automatic Generation Control
- BAL-006-2 – Inadvertent Interchange

The Project 2010-14.2 standard drafting team is proposed to consist of a maximum of 10 members. Additional information about the project is available on the project page. Standard drafting team members should have experience in one or more of the following areas: transmission operations, Balancing Authority operations including AGC operation, generation operations, and inadvertent interchange. In addition, team members with experience in compliance, legal, regulatory and technical writing is desired. Previous drafting team experience is beneficial, but not a requirement.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Electronic Nomination Form

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team:

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ ERCOT	☐ NPCC	☐ SPP
☐ FRCC	☐ RFC	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:

☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:

☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.2 Balancing Authority Reliability-based Control Standard Authorization Request BAL-005 and BAL-006

Informal Comment Period Now Open through August 14, 2014
Standard Drafting Team Nomination Period Open through July 30, 2014

Now Available

A 30-day informal comment period for the **Project 2010-14.2 Balancing Authority Reliability-based Control** Standard Authorization Request (SAR) is now open through **8 p.m. Eastern on Thursday, August 14, 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.

Instructions for Submitting a Nomination

If you are interested in serving on the Standard Drafting Team, please complete the nomination form by **July 30, 2014**. The nomination form should be submitted describing the individual's experience or qualifications related to the project.

Link to Official Nomination Form

An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

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

Standards Announcement

Project 2010-14.2 Balancing Authority Reliability-based Control Standard Authorization Request BAL-005 and BAL-006

Informal Comment Period Now Open through August 14, 2014
Standard Drafting Team Nomination Period Open through July 30, 2014

Now Available

A 30-day informal comment period for the **Project 2010-14.2 Balancing Authority Reliability-based Control** Standard Authorization Request (SAR) is now open through **8 p.m. Eastern on Thursday, August 14, 2014.**

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Individual or group. (19 Responses)
Name (8 Responses)
Organization (8 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Contact Organization (11 Responses)
Question 1 (18 Responses)
Question 1 Comments (18 Responses)
Question 2 (18 Responses)
Question 2 Comments (18 Responses)
Question 3 (14 Responses)
Question 3 Comments (18 Responses)
Question 4 (0 Responses)
Question 4 Comments (18 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
BAL-006 Requirement R4 was recommended to be retired by the independent Expert Recommnedation Report (IERR) as it was only for energy accounting. The Periodic Review Team (PRT) disagreed with the IERR claiming that there was a reliability concern if adjacent BAs did not agree to NSI and NAI in a timely manner. The accounting occurs after the fact. Can the PRT provide examples of what reliability issues the revised requirement would guard against? What would a new “timely basis” be? As long as the agreement between BAs continues to be after the fact, regardless of the “timely basis”, there isn’t a potential reliability issue and agrees with the IERR recommendation in favor of retiring the requirement. The new definition of Inadvertent Interchange will still be covered by the revised requirements R1 and R2 if requirement R4 is retired as per the IERR recommendation.
No
Individual
Thomas Foltz
American Electric Power
Yes
There needs to be a mechanism to allow the BA to gather what they need from the other functional entities in calculating ACE. It appears that the SAR may lead in a direction that removes the TOP, LSE, and GOP from the standard, leaving “stranded obligations” where no requirements remain which would obligate the TOP, LSE, or GOP to provide the BA what it needs. The SAR states that consideration is being given to include similar oblibations as part of a FAC standard, however we are not certain we could support the proposed changes to BAL-005 without also seeing exactly how it will be addressed in the FAC standard(s). In addition, rather than adding such obligations solely to a FAC standard, AEP believes the best approach would be to add the obligation as a separate requirement within BAL-005 (as a real time obligation) *and* the FAC standard (as a forward looking obligation). The SAR removes the GOP, TOP, and LSE from the standard while also stating the drafting team’s intent to explore whether the role of TOP could assume the obligations of the LSE. The TOP and LSE are separate entities with unique obligations as specified in the NERC glossary. Requiring the TOP to assume the obligations of the LSE could prove very problematic, blurring roles which are currently well defined.
No

No
AEP is not aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s).
Individual
Greg Travis
Idaho Power
No
No
No
Group
MRO NERC Standards Review Forum
Joe DePoorter
Madison Gas & Electric
Yes
The general scope of the SAR is fine. The challenge is the SAR covers the entire scope recommended by the Periodic Review Team. The PRT work was out for comment and to our knowledge no changes were made to the PRT's recommendations based on comments received. We had concerns with some of the PRT proposals and the previous comments should be addressed prior to substantive work.
Yes
ERCOT and HQ do not have Inadvertent Interchange. Additionally, any material changes to BAL-006 would need to be coordinated with NAESB.
Yes
While there are Order No. 693 directives for these standards, several of these directives may have become immaterial (e.g. directive may be to make a paragraph 81-type change) or counter-productive at this point. The drafting team should focus on creating streamlined high-quality results-based standards. If a directive causes a problem or does not add value to reliability, the drafting team should document their reasoning and not blindly make changes.
As we are unsure of what was done with our prior comments from April, we are providing them here. General Comments on BAL-005 • We agree with streamlining the standard and making it clearer. • While we are OK with changing the title of the standard, we have concerns about removing the term "Automatic Generation Control". This term is or its acronym are used well over 50 times in the standards and are commonly understood in the industry (tens of thousands of references to it on the internet). Given the intent of the FERC directive, we propose changing the exiting definition in the NERC glossary to : Equipment that automatically adjusts generation and other resources in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. • We agree with removing all entities other than Balancing Authorities in the applicability section, but disagree with moving some of the requirements to a FAC standard (reasons explained below). Specific Comments on BAL-005 • On the current R1 (and R3), we agree with removing the requirements about generation, load and transmission be within the metered bounds of a BA. These requirements also should not be punted to a FAC standard. These were "control area criteria" (i.e. concepts) that were swept into the V0 standard. The proof that all load, generation and transmission is within metered bounds is achieved via Inadvertent Accounting. There is no need for a different explicit requirement. BAs should be the only applicable entity in this standard. • On the current R3 and R4: We believe these requirements are important and generally should remain as-is (although they could be consolidated). We also believe that avoidance of Burden (a defined and

understandable term) is a reasonable objective for the requirement(s). • The current R5 would not be necessary if all BAs had to report their control performance. The problem is the current practice whereby BAs who receive overlap regulation don't have to report their performance. Thus, we believe this requirement should stay. It only applies to a relatively small proportion of BAs. • With regard to the redline R2, the team appears to be duplicating requirements in the INT standards. A BA should not be subject to multiple non-compliances for missing a schedule. • With regard to the redline R3, R3.1 is a piece of information and not a requirement. R3.4 is redundant with the parent requirement. There is no requirement today to swap hourly values, and this should not be added. • The redline R3.5 should be simplified to "ACE source data shall be acquired and ACE calculated at least every 6 seconds). R3.5.2. is redundant with R3.2 and should be eliminated. General Comments and Comments on PRT Recommendations for BAL-006 • We agree with eliminating the redundant requirements and moving the real-time requirements to BAL-005. • On the PRT recommendation for R1, we disagree with the proposal to add a performance metric with regard to inadvertent interchange. The other balancing standards adequately address the reliability impact of imbalance. • On the PRT recommendation for R2, we disagree with the need to change the definition of Inadvertent Interchange to add the complexity mentioned. If both parties to a transaction agree to a common number and have operated against common points in real time, it makes no difference to the Interconnection. • On the PRT recommendation for R3, we disagree with the need to "swap" hourly values. There are many tools in place to detect significant and persistent metering and balancing errors. There has not been a need to call an AIE survey for at least 5 years. At most, we would suggest a requirement in BAL-005 for each BA to share in real time its NIa with each adjacent BA and its RC as well as share its NIs with its RC. This would accommodate the "cross check" the PRT appears to be seeking. If this requirement were added, the other proposed "granular" requirements in BAL-005 on pseudo-ties and dynamic schedules could likely be simplified. This adjacent information is already an implied requirement in Attachment 1-TOP-005. • On the PRT recommendation for R4 and its sub-requirements, we disagree with the suggestion of adding complexity to the definition of Inadvertent Interchange and of performing and reporting more frequently as well as the suggestion again for a performance requirement. • On the PRT recommendation for R5, we believe the current requirement is acceptable as-is. • The proposed changes to definitions look acceptable. Specific Comments on BAL-006 • On the redline R1.3 and R1.4, these should be changed to reflect the current practice that monthly data is to be submitted and agreed to with counterparties in the Inadvertent Interchange reporting portal.
Individual
Leonard Kula
Independent Electricity System Operator
Yes
BAL-006 Requirement R4 was recommended to be retired by the Independent Expert Recommendation Report (IERR) as it was only for energy accounting. The Periodic Review Team (PRT) disagreed with the IERR claiming that there was a reliability concern if Adjacent BA's did not agree to NSI and NAI in a timely manner. The IESO questions this concern, given that the accounting occurs after-the-fact. Can the PRT provide examples of what reliability issues the revised requirement would guard against? What would a new "timely basis" be? As long as the the agreement between BA's continues to be after-the-fact, regardless of the "timely basis", the IESO does not see a potential reliability issue and agrees with the IERR recommendation in favour of retiring the requirement. The new definition of Inadvertent Interchange will still be covered by the revised Requirement 1 and 2 if requirement 4 was to be retired as per the IERR recommendation.
No
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
Marcus Pelt

Southern Company Compliance
No
No
No
Individual
Eric Scott
Ameren
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
In the 3rd line of the Objectives section, delete the 2nd ‘define’. Be consistent with the capitalization of Real-time throughout the SAR. For BAL-005 Reword the end of the next-to-last sentence in the overview of BAL-005 on Page 3 to read: ‘…the PRT recommends requirements which are focused on Real-time operating data. Effectively changing the definition of AGC may be confusing since AGC is an acronym for automatic generation control. You can take generation out of the definition but AGC will always be automatic generation control. We suggest a total change of the term. If it is to reference control of all resources, why not label it automatic resource control (ARC). Then the acronym fits the terminology. Purpose – While concurring with the proposed change to the purpose, we suggest replacing ‘under’ with ‘using’. Also, since Tie Line Bias is the defined term not Tie Line Bias control, don’t capitalize control. In the sentence following the proposed purpose, capitalize Tie Line Bias and insert ‘interconnection’ between ‘single-BA’ and ‘exception’. Applicability – We suggest modifying this to read: ‘The SDT should remove “Generator Operators”, “Transmission Operators”, and “Load Serving Entities” as applicable entities unless they are specifically included in a standard requirement by the SDT.’ Requirement R1 – In the 4th line insert ‘regarding’ between ‘FAC SDT’ and ‘moving’. Requirement R3 – The sentence in the 9th line that reads ‘Specific to the concern on swapping hourly values in BAL-005 posted for industry comment.’ doesn’t make any sense. Has something been left out? Split the next sentence into two sentences by replacing the comma after ‘R3.5.2’ with a period and capitalizing ‘The’ to begin the second sentence. Requirement R6 – Delete the ‘the’ at the end of the 3rd line. Requirement R7 – In the last line replace the ‘where’ with ‘and’. Requirement R9, Part 9.1 – Rewrite the last sentence to read: ‘By focusing on Real-time Reporting ACE, the PRT assures reliability is addressed and maintained at all times.’ Requirement R14 – Replace the ‘for’ in the next-to-last line with ‘and considered during’.
No
No
There were several documents (redlined standards, Consideration of Comments, directives and issues, IERP recommendations) mentioned in the Unofficial Comment Form which indicated they were included in this posting but they aren’t on the project page.
Individual
Karin Schweitzer
Texas Reliability Entity, Inc.
Yes
BAL-005 1) Purpose statement: Texas Reliability Entity, Inc. (Texas RE) requests that the purpose statement be revised to remove “under Tie-Line Bias Control.” ERCOT has only DC ties modeled as internal generation or load and effectively utilizes only freqency bias control. 2) R3.2 and 1st sentence of R3.5.2: Texas RE requests the rationale for moving hourly error checking from

Requirement R3.2 and R3.5.2 to a guideline document be clearly documented within the draft revision. 3) R13: Texas RE requests the rationale for moving hourly error checking from Requirement R13 to a guideline document be clearly documented within the draft revision. BAL-006 While the ERCOT region does not have issues with coordination of accounting figures between Adjacent Balancing Authorities, Texas RE supports the proposed revisions.
No
The issues which are unique to the ERCOT region would be addressed by the suggested changes made by Texas RE in response to Question 1 for BAL-005.
No
Group
Bureau of Reclamation
Erika Doot
Power Resources Office
Yes
The Bureau of Reclamation supports the drafting team's recommendation to remove Generator Operators (GOPs), Transmission Operators (TOPs), and Load Serving Entities (LSEs) from the scope of BAL-005. Reclamation believes that generation and transmission interconnection requirements ensure that facilities are within the metered boundaries of a Balancing Authority area before they are placed in service. Reclamation notes that this requirement has imposed a compliance paperwork burden on GOPs, TOPs, and LSEs because Balancing Authorities are not required to provide information confirming that facilities are within the metered boundaries of a balancing authority area under the standard, and this effort has not provided a corresponding reliability benefit. In the alternative, Reclamation suggests that Balancing Authorities be required to coordinate to ensure that all facilities fall within their metered boundaries because BAs determine the boundaries.
No
No
Group
Duke Energy
Michael Lowman
Duke Energy
No
No
No
Comments: Duke Energy thanks the Periodic Review Team for their efforts, and would like to express our support for the recommendations made. The following comments are suggestions for the standard drafting team's consideration. General Comment re: BAL-005:Unless the Standard Drafting Team chooses to revise, a re-post of the red-lined version of the current BAL-005 is necessary so that it may accurately reflect the numbering of the original version. Duke Energy agrees with the PRT's recomendation that the NERC Glossary of Terms defintion of ACE and Reporting ACE should be reviewed. In addition, we agree that a comprehensive review of the NERC standards is necessary to ensure that any updates/revsions to the NERC definitions mentioned above would not impact other NERC Reliability Standards. 1) Requirement 1: Duke Energy echoes the concerns of the Periodic Review Team in ensuring to keep responsibility of staying in a metered boundary with the LSE, TOP, and GOP. We do not agree with the possibility of placing this

responsibility with the BA. 2) Requirement 13: We agree with the approach suggested by the Periodic Review Team. Also, we support the development of a guideline document to further expand on the topic, and clarify any potential ambiguities that may exist. 3)Requirement 14: Duke Energy is in agreement with the industry comments referenced by the Periodic Review Team for this requirement. If covered elsewhere, we feel that this requirement should be retired.
Group
ISO Standards Review Committee
Terry Bilke
MISO
Yes
The SRC supports the comments included in BAL-005, R1 regarding the correct boundaries for applicability to the BA versus LSE, TOP and GOP for specific obligations.
Yes
ERCOT and HQ do not have Inadvertent Interchange. Additionally, any material changes to BAL-006 would need to be coordinated with NAESB.
Yes
While there are Order No. 693 directives for these standards, several of these directives may have become immaterial (e.g. directive may be to make a paragraph 81-type change) or counter-productive at this point. The drafting team should focus on creating streamlined high-quality results-based standards. If a directive causes a problem or does not add value to reliability, the drafting team should document their reasoning and not blindly make changes.
The general scope of the SAR is fine. The challenge is the SAR covers the entire scope recommended by the Periodic Review Team and also references a separate document. A SAR is intended to set the general bounds of a standard. Our approval of the SAR does not imply we agree with everything included. We strongly request that the previous comments submitted earlier in the year be addressed prior to substantive work.
Group
DTE Electric Co.
Kathleen Black
NERC Training & Standards Development
No
No
No
We agree that R15 of BAL-005 belongs in EOP-008.
Individual
Jo-Anne Ross
Manitoba Hydro
No
No
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Standards Group

No
No
No
Group
ACES Standards Collaborators
Ben Engelby
ACES
Yes
We agree we the SAR's recommendation to revise BAL-005 and BAL-006. We support the 5-year review team's recommendation of removing the TOP, GOP, and LSE functions from the applicability section of BAL-005 and to retire or consolidate several requirements. We also support the team's recommendations to retire many of the requirements in BAL-006.
No
We are not aware of regional variances or business practices that need to be considered.
No
We are not aware of any Canadian provincial or other regulatory requirements that need to be considered.
We will provide specific comments on the proposed changes to the standards after the SAR is approved and the formal standards development process begins. Thank you for the opportunity to comment.
Individual
Chris Scanlon
Exelon companies, BGE, ComEd, PECO
No
No
No
Exelon recognizes that this is a large Project. We appreciate the scope of the proposed changes and encourage the drafting team to be cautious so as to not re-assign obligations to other entities if requirements are "mapped" to other Standards. In general, Exelon agrees with the changes proposed in the SAR and to changes in the applicability, including the removal of the LSE. We note however, changes to LSE applicable requirements need to be considered in light of the RRB initiative. Exelon believes that applicability for R17 is solely to the Balancing Authority; we agree with the PRT recommendation that BAL-005 R17 be written to be specific to the equipment used to determine the frequency component required for reporting ACE as is detailed in the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17. See Appendix 1 which limits the requirement to BA frequency monitoring.
Group
Associated Electric Cooperative, Inc. - JRO00088
Phil Hart
Associated Electric Cooperative, Inc. - NCR01177
Yes
The PRT has argued the IERP recommendation stating hourly meter checkouts are not a reliability related task, but purely economic. AECI agrees with the PRT that it is a helpful process in identifying errors in tie values, however as long as an entities ACE is established, (which is required by other

standards) no real risk to reliability is taken, merely economic settlement on the errors within the meters. The PRT has created a requirement that addresses identifying and troubleshooting errors with interchange (draft BAL-005 R3.5.2), without requiring specific hourly checkouts of every meter on the system. This is something entities are extremely concerned with for economic reasons so there is no doubt the action will be performed, but creating this as a requirement only creates administrative burden without any additional benefit to reliability (NAI error checks are already required in R3.5.2). For this reason, the currently drafted BAL-005 R3.2 is redundant with R3.5.2. AECI requests that the SDT strike R3.2.
No
No
Individual
Richard Vine
California ISO
Yes
The ISO supports the comments submitted by the ISO/RTO Council Standards Review Committee
Yes
The ISO supports the comments submitted by the ISO/RTO Council Standards Review Committee
BAL-005 requirement R8 presently states: “The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds." In order for this requirement to have the desired effect of ensuring a Balancing Authority’s ACE value is refreshed and accurate as of every six seconds, the tie line metering data being sampled by each Balancing Authority must also be accurate and updated at least every six seconds. Therefore, the ISO recommends that the SAR include within its scope the requirement for ensuring the tie line meter data being relied on for the “data acquisition for and calculation of ACE” is updated at least every six seconds to match the required sampling frequency.

Consideration of Comments

Project 2010-14.2 Periodic Review of BAL Standards

The Project 2010-14.2 Drafting Team thanks all commenters who submitted comments on the Standards Authorization Request (SAR). These standards were posted for a 30-day public comment period from July 16, 2014 through August 14, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 19 sets of comments, including comments from approximately 95 different people from approximately 75 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, at 404-446-9693 or by e-mail. 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

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.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	Nw 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.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
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

Additional Member	Additional Organization	Region	Segment Selection
10. Mark Kenny	Northeast Utilities	NPCC	1
11. Helen Lainis	Independent Electricity System Operator	NPCC	2
12. Alan MacNaughton	New Brunswick Power Corporation	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. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21. Brian Shanahan	National Grid	NPCC	1
22. Wayne Sipperly	New York Power Authority	NPCC	5
23. Ben Wu	Orange and Rockland Utilties Inc.	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Joe DePoorter	MRO NERC Standards Review Forum		X	X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Amy Casuccelli	Xcel Energy	MRO	1, 3, 5, 6
2. Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3. Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5. Kayliegh Wilkersonq	Lincoln Electric System	MRO	1, 3, 5, 6
6. Jodi Jensen	Western Area Power Administration	MRO	1, 6
7. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8. Ken Goldsmith	Alliant Energy	MRO	4
9. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10. Marie Knox	MISO	MRO	2
11. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12. Randi Nyholm	Minnesota Power	MRO	1, 5
13. Scott Nickels	Rochester Public Utilities	MRO	4
14. Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allan George	Sunflower Electric Power Corporation	SPP	1
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
3.	Phil Hart	Associated Electric Cooperative	SERC	1, 3, 5, 6
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3, 5
10.	Carl Stelly	Southwest Power Pool	SPP	2
11.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Erika Doot	Bureau of Reclamation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Richard Jackson	Power Resources Office	WECC	5
2.	George Girgis	Technical Services Center	WECC	1, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Michael Lowman	Duke Energy			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils			1
2.	Lee Schuster			3
3.	Dale Goodwine			5
4.	Greg Cecil			6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Terry Bilke	ISO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	Greg Campoli	NYISO	NPCC	2
3.	Ben Li	IESO	NPCC	2
4.	Kathleen Goodman	ISO-NE	NPCC	2
5.	Cheryl Moseley	ERCOT	ERCOT	2
6.	Cathy Wesley	PJM	RFC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Kathleen Black	DTE Electric Co.			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Trainng & Standards Development	RFC	4
3.	Mark Stefaniak	Generation Optimization	RFC	5
4.	Barbara Hollan	DO/SOC		

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Sheryl Welch	Public Utilities Specialist	WECC	1
2.	Wes Hutchison	Commercial System Management	WECC	1
3.	Gordon Markley	Electrical Engineer	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
3.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
4.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 2, 3
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1, 2, 3
6.	Lucia Beal	Southern Maryland Electric Cooperative, Inc.	RFC	3
7.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
8.	Ginger Mercier	Prairie Power, Inc.	SERC	1, 2, 3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Phil Hart	Associated Electric Cooperative, Inc. - JRO00088			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
9.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
10.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Thomas Foltz	American Electric Power			X		X	X				
13.	Individual	Greg Travis	Idaho Power										
14.	Individual	Leonard Kula	Independent Electricity System Operator		X								
15.	Individual	Eric Scott	Ameren			X		X	X				
16.	Individual	Karin Schweitzer	Texas Reliability Entity, Inc.										X
17.	Individual	Jo-Anne Ross	Manitoba Hydro			X		X	X				
18.	Individual	Chris Scanlon	Exelon companies, BGE, ComEd, PECO			X		X	X				
19.	Individual	Richard Vine	California ISO		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"
Ameren	Agree	We agree with and support MISO's comments for BAL-005 and BAL-006.

1. **Do you have any specific questions or comments relating to the scope of the proposed standard action or any component of the SAR outside of the pro forma standard?**

Summary Consideration:

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	No	
Duke Energy	No	
DTE Electric Co.	No	
Bonneville Power Administration	No	
Idaho Power	No	
Manitoba Hydro	No	
Exelon companies, BGE, ComEd, PECO	No	
Northeast Power Coordinating Council	Yes	BAL-006 Requirement R4 was recommended to be retired by the independent Expert Recommnedation Report (IERR) as it was only for energy accounting. The Periodic Review Team (PRT) disagreed with the

Organization	Yes or No	Question 1 Comment
		IERR claiming that there was a reliability concern if adjacent BAs did not agree to NSI and NAI in a timely manner. The accounting occurs after the fact. Can the PRT provide examples of what reliability issues the revised requirement would guard against? What would a new "timely basis" be? As long as the agreement between BAs continues to be after the fact, regardless of the "timely basis", there isn't a potential reliability issue and agrees with the IERR recommendation in favor of retiring the requirement. The new definition of Inadvertent Interchange will still be covered by the revised requirements R1 and R2 if requirement R4 is retired as per the IERR recommendation. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard.
MRO NERC Standards Review Forum	Yes	The general scope of the SAR is fine. The challenge is the SAR covers the entire scope recommended by the Periodic Review Team. The PRT work was out for comment and to our knowledge no changes were made to the PRT's recommendations based on comments received. We had concerns with some of the PRT proposals and the previous comments should be addressed prior to substantive work. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard.
SPP Standards Review Group	Yes	In the 3rd line of the Objectives section, delete the 2nd 'define'.Be consistent with the capitalization of Real-time throughout the SAR.For BAL-005Reword the end of the next-to-last sentence in the overview of BAL-005 on Page 3 to read: '...the PRT recommends requirements which are focused on Real-time operating data.

Organization	Yes or No	Question 1 Comment
		Thank you for your comments. Effectively changing the definition of AGC may be confusing since AGC is an acronym for automatic generation control. You can take generation out of the definition but AGC will always be automatic generation control. We suggest a total change of the term. If it is to reference control of all resources, why not label it automatic resource control (ARC). Then the acronym fits the terminology. The SDT believes that the term Automatic Generation Control (AGC) should not be changed since it is used extensively throughout the NERC standards. Purpose - While concurring with the proposed change to the purpose, we suggest replacing 'under' with 'using'. Also, since Tie Line Bias is the defined term not Tie Line Bias control, don't capitalize control. The SDT does not reference the phrase "under Tie-Line Bias Control". In the sentence following the proposed purpose, capitalize Tie Line Bias and insert 'interconnection' between 'single-BA' and 'exception'. Thank you for your comment. The SDT does not believe that the suggested modification provides for additional clarity. Applicability - We suggest modifying this to read: 'The SDT should remove "Generator Operators", "Transmission Operators", and "Load Serving Entities" as applicable entities unless they are specifically included in a standard requirement by the SDT.' Thank you for your comment. The SDT does not believe that the suggested modification provides for additional clarity. Requirement R1 - In the 4th line insert 'regarding' between 'FAC SDT' and 'moving'. Thank you for your comment.

Organization	Yes or No	Question 1 Comment
		Requirement R3 - The sentence in the 9th line that reads ‘Specific to the concern on swapping hourly values in BAL-005 posted for industry comment.’ doesn’t make any sense. Has something been left out? Thank you for your comment. Split the next sentence into two sentences by replacing the comma after ‘R3.5.2’ with a period and capitalizing ‘The’ to begin the second sentence. Thank you for your comment. Requirement R6 - Delete the ‘the’ at the end of the 3rd line. Thank you for your comment. Requirement R7 - In the last line replace the ‘where’ with ‘and’. Thank you for your comment. The SDT does not believe that the suggested modification provides for additional clarity. Requirement R9, Part 9.1 - Rewrite the last sentence to read: ‘By focusing on Real-time Reporting ACE, the PRT assures reliability is addressed and maintained at all times.’ Thank you for your comment. The SDT does not believe that the suggested modification provides for additional clarity. Requirement R14 - Replace the ‘for’ in the next-to-last line with ‘and considered during’. Thank you for your comment. The SDT does not believe that the suggested modification provides for additional clarity.
Bureau of Reclamation	Yes	The Bureau of Reclamation supports the drafting team’s recommendation to remove Generator Operators (GOPs), Transmission Operators (TOPs), and Load Serving Entities (LSEs) from the scope of BAL-005. Reclamation believes that generation and transmission interconnection requirements

Organization	Yes or No	Question 1 Comment
		ensure that facilities are within the metered boundaries of a Balancing Authority area before they are placed in service. Reclamation notes that this requirement has imposed a compliance paperwork burden on GOPs, TOPs, and LSEs because Balancing Authorities are not required to provide information confirming that facilities are within the metered boundaries of a balancing authority area under the standard, and this effort has not provided a corresponding reliability benefit. In the alternative, Reclamation suggests that Balancing Authorities be required to coordinate to ensure that all facilities fall within their metered boundaries because BAs determine the boundaries. The SDT agrees with your comment and has removed them from the draft standard.
ISO Standards Review Committee	Yes	The SRC supports the comments included in BAL-005, R1 regarding the correct boundaries for applicability to the BA versus LSE, TOP and GOP for specific obligations. The SDT agrees with your comment and has removed them from the draft standard.
ACES Standards Collaborators	Yes	We agree we the SAR's recommendation to revise BAL-005 and BAL-006. We support the 5-year review team's recommendation of removing the TOP, GOP, and LSE functions from the applicability section of BAL-005 and to retire or consolidate several requirements. We also support the team's recommendations to retire many of the requirements in BAL-006. The SDT agrees with your comment and has removed them from the draft standard BAL-005. The SDT is still reviewing BAL-006.
Associated Electric Cooperative, Inc. - JRO00088	Yes	The PRT has argued the IERP recommendation stating hourly meter checkouts are not a reliability related task, but purely economic.

Organization	Yes or No	Question 1 Comment
		AECI agrees with the PRT that it is a helpful process in identifying errors in tie values, however as long as an entities ACE is established, (which is required by other standards) no real risk to reliability is taken, merely economic settlement on the errors within the meters. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard. The PRT has created a requirement that addresses identifying and troubleshooting errors with interchange (draft BAL-005 R3.5.2), without requiring specific hourly checkouts of every meter on the system. This is something entities are extremely concerned with for economic reasons so there is no doubt the action will be performed, but creating this as a requirement only creates administrative burden without any additional benefit to reliability (NAI error checks are already required in R3.5.2). For this reason, the currently drafted BAL-005 R3.2 is redundant with R3.5.2. AECI requests that the SDT strike R3.2. The SDT has modified the draft standard to address your concern in an equally effective and efficient manner.
American Electric Power	Yes	There needs to be a mechanism to allow the BA to gather what they need from the other functional entities in calculating ACE. It appears that the SAR may lead in a direction that removes the TOP, LSE, and GOP from the standard, leaving “stranded obligations” where no requirements remain which would obligate the TOP, LSE, or GOP to provide the BA what it needs. The SAR states that consideration is being given to include similar oblibations as part of a FAC standard, however we are not certain we could support the proposed changes to BAL-005 without also seeing exactly how it will be addressed in the FAC standard(s). In addition, rather than adding such obligations solely to a FAC standard, AEP believes the best approach

Organization	Yes or No	Question 1 Comment
		would be to add the obligation as a separate requirement within BAL-005 (as a real time obligation) *and* the FAC standard (as a forward looking obligation).The SAR removes the GOP, TOP, and LSE from the standard while also stating the drafting team's intent to explore whether the role of TOP could assume the obligations of the LSE. The TOP and LSE are separate entities with unique obligations as specified in the NERC glossary. Requiring the TOP to assume the obligations of the LSE could prove very problematic, blurring roles which are currently well defined. The SDT agrees with your comment and has revised both BAL-005 and FAC-001 to address your concern.
Independent Electricity System Operator	Yes	BAL-006 Requirement R4 was recommended to be retired by the Independent Expert Recommendation Report (IERR) as it was only for energy accounting. The Periodic Review Team (PRT) disagreed with the IERR claiming that there was a reliability concern if Adjacent BA's did not agree to NSI and NAI in a timely manner. The IESO questions this concern, given that the accounting occurs after-the-fact. Can the PRT provide examples of what reliability issues the revised requirement would guard against? What would a new "timely basis" be? As long as the the agreement between BA's continues to be after-the-fact, regardless of the "timely basis", the IESO does not see a potential reliability issue and agrees with the IERR recommendation in favour of retiring the requirement. The new definition of Inadvertent Interchange will still be covered by the revised Requirement 1 and 2 if requirement 4 was to be retired as per the IERR recommendation. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard.
Texas Reliability Entity, Inc.	Yes	BAL-005

Organization	Yes or No	Question 1 Comment
		1) Purpose statement: Texas Reliability Entity, Inc. (Texas RE) requests that the purpose statement be revised to remove “under Tie-Line Bias Control.” ERCOT has only DC ties modeled as internal generation or load and effectively utilizes only freqency bias control. The SDT does not reference the phrase “under Tie-Line Bias Control”. 2) R3.2 and 1st sentence of R3.5.2: Texas RE requests the rationale for moving hourly error checking from Requirement R3.2 and R3.5.2 to a guideline document be clearly documented within the draft revision. The SDT believes that by using a common data source the possibility for errors due to different values is minimized. 3) R13: Texas RE requests the rationale for moving hourly error checking from Requirement R13 to a guideline document be clearly documented within the draft revision. This requirement was broken apart and is now a part of Requirements R1 and R7. BAL-006 While the ERCOT region does not have issues with coordination of accounting figures between Adjacent Balancing Authorities, Texas RE supports the proposed revisions. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard.
California ISO	Yes	The ISO supports the comments submitted by the ISO/RTO Council Standards Review Committee Thank you for your comment and please review the response to the ISO/RTO Council SRC.

2. **If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	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	No	
SPP Standards Review Group	No	
Bureau of Reclamation	No	
Duke Energy	No	
DTE Electric Co.	No	

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	No	
ACES Standards Collaborators	No	We are not aware of regional variances or business practices that need to be considered. Thank you for your comment.
Associated Electric Cooperative, Inc. - JRO00088	No	
American Electric Power	No	
Idaho Power	No	
Independent Electricity System Operator	No	
Texas Reliability Entity, Inc.	No	The issues which are unique to the ERCOT region would be addressed by the suggested changes made by Texas RE in response to Question 1 for BAL-005. Thank you for your comment and please review the response to Question #1.
Manitoba Hydro	No	
Exelon companies, BGE, ComEd, PECO	No	
MRO NERC Standards Review Forum	Yes	ERCOT and HQ do not have Inadvertent Interchange. Additionally, any material changes to BAL-006 would need to be coordinated with NAESB.

Organization	Yes or No	Question 2 Comment
		Thank you for your comment. The SDT will be consulting with NAESB when it is evaluating BAL-006 for possible revisions.
ISO Standards Review Committee	Yes	ERCOT and HQ do not have Inadvertent Interchange. Additionally, any material changes to BAL-006 would need to be coordinated with NAESB. Thank you for your comment. The SDT will be consulting with NAESB when it is evaluating BAL-006 for possible revisions.
California ISO	Yes	The ISO supports the comments submitted by the ISO/RTO Council Standards Review Committee Thank you for your comment and please review the response to the ISO/RTO Council SRC.

3. **Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements**

Summary Consideration:

Organization	Yes or No	Question 3 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	No	
SPP Standards Review Group	No	
Bureau of Reclamation	No	
Duke Energy	No	
DTE Electric Co.	No	
Bonneville Power Administration	No	

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	We are not aware of any Canadian provincial or other regulatory requirements that need to be considered. Thank you for your comment.
Associated Electric Cooperative, Inc. - JRO00088	No	
American Electric Power	No	AEP is not aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s). Thank you for your comment.
Idaho Power	No	
Texas Reliability Entity, Inc.	No	
Exelon companies, BGE, ComEd, PECO	No	
MRO NERC Standards Review Forum	Yes	While there are Order No. 693 directives for these standards, several of these directives may have become immaterial (e.g. directive may be to make a paragraph 81-type change) or counter-productive at this point. The drafting team should focus on creating streamlined high-quality results-based standards. If a directive causes a problem or does not add value to reliability, the drafting team should document their reasoning and not blindly make changes. Thank you for your comment.
ISO Standards Review Committee	Yes	While there are Order No. 693 directives for these standards, several of these directives may have become immaterial (e.g. directive may be to make a paragraph 81-type change) or counter-productive at this point. The drafting team should focus

Organization	Yes or No	Question 3 Comment
		on creating streamlined high-quality results-based standards. If a directive causes a problem or does not add value to reliability, the drafting team should document their reasoning and not blindly make changes. Thank you for your comment.

4. If you have any other comments on this SAR that you haven't already mentioned, please provide them here

Summary Consideration:

Organization	Question 4 Comment
MRO NERC Standards Review Forum	As we are unsure of what was done with our prior comments from April, we are providing them here. General Comments on BAL-005 o We agree with streamlining the standard and making it clearer. Thank you for your comment. o While we are OK with changing the title of the standard, we have concerns about removing the term "Automatic Generation Control". This term is or its acronym are used well over 50 times in the standards and are commonly understood in the industry (tens of thousands of references to it on the internet). Given the intent of the FERC directive, we propose changing the exiting definition in the NERC glossary to : Equipment that automatically adjusts generation and other resources in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. The SDT agrees and has modified the definition in an equally effective manner to that which you have proposed. o We agree with removing all entities other than Balancing Authorities in the applicability section, but disagree with moving some of the requirements to a FAC standard (reasons explained below).

Organization	Question 4 Comment
	Specific Comments on BAL-005 o On the current R1 (and R3), we agree with removing the requirements about generation, load and transmission be within the metered bounds of a BA. These requirements also should not be punted to a FAC standard. These were “control area criteria” (i.e. concepts) that were swept into the V0 standard. The proof that all load, generation and transmission is within metered bounds is achieved via Inadvertent Accounting. There is no need for a different explicit requirement. BAs should be the only applicable entity in this standard. The SDT disagrees with your comment. The SDT believes that Inadvertent Accounting does not guarantee everything is captured – as proposed R1 and R2 is intended to capture all facilities within the BA. o On the current R3 and R4: We believe these requirements are important and generally should remain as-is (although they could be consolidated). We also believe that avoidance of Burden (a defined and understandable term) is a reasonable objective for the requirement(s). The SDT has incorporated the intent of these requirements into other requirement within the standard (Requirements R1 and R8). o The current R5 would not be necessary if all BAs had to report their control performance. The problem is the current practice whereby BAs who receive overlap regulation don’t have to report their performance. Thus, we believe this requirement should stay. It only applies to a relatively small proportion of BAs. The SDT has incorporated the intent of these requirements into other requirement within the standard (Requirements R1 and R8). o With regard to the redline R2, the team appears to be duplicating requirements in the INT standards. A BA should not be subject to multiple non-compliances for missing a schedule. The SDT has modified the requirement to ensure no duplication.

Organization	Question 4 Comment
	o With regard to the redline R3, R3.1 is a piece of information and not a requirement. R3.4 is redundant with the parent requirement. There is no requirement today to swap hourly values, and this should not be added. The SDT agrees and has made the necessary modifications. o The redline R3.5 should be simplified to "ACE source data shall be acquired and ACE calculated at least every 6 seconds). R3.5.2. is redundant with R3.2 and should be eliminated. The SDT agrees and has made the necessary modifications. General Comments and Comments on PRT Recommendations for BAL-006 o We agree with eliminating the redundant requirements and moving the real-time requirements to BAL-005. o On the PRT recommendation for R1, we disagree with the proposal to add a performance metric with regard to inadvertent interchange. The other balancing standards adequately address the reliability impact of imbalance. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard. o On the PRT recommendation for R2, we disagree with the need to change the definition of Inadvertent Interchange to add the complexity mentioned. If both parties to a transaction agree to a common number and have operated against common points in real time, it makes no difference to the Interconnection. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard. o On the PRT recommendation for R3, we disagree with the need to "swap" hourly values. There are many tools in place to detect significant and persistent metering and balancing errors. There has not been a need to call an AIE survey for at least 5 years.

Organization	Question 4 Comment
	At most, we would suggest a requirement in BAL-005 for each BA to share in real time its NIa with each adjacent BA and its RC as well as share its NIs with its RC. This would accommodate the "cross check" the PRT appears to be seeking. If this requirement were added, the other proposed "granular" requirements in BAL-005 on pseudo-ties and dynamic schedules could likely be simplified. This adjacent information is already an implied requirement in Attachment 1-TOP-005. The SDT disagrees with your comment concerning the swapping of values. The SDT believes that his practice will help to guarantee a more accurate Reporting ACE value. o On the PRT recommendation for R4 and its sub-requirements, we disagree with the suggestion of adding complexity to the definition of Inadvertent Interchange and of performing and reporting more frequently as well as the suggestion again for a performance requirement. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard. o On the PRT recommendation for R5, we believe the current requirement is acceptable as-is. Thank you for your comment. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard. o The proposed changes to definitions look acceptable. Thank you for your comment. Specific Comments on BAL-006 o On the redline R1.3 and R1.4, these should be changed to reflect the current practice that monthly data is to be submitted and agreed to with counterparties in the Inadvertent Interchange reporting portal. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take

Organization	Question 4 Comment
	your comment into consideration as it reviews the current standard. However, some information should be within a guideline paper rather than a standard (guideline is more of how to accomplish - a standard should not define how to accomplish).
California ISO	BAL-005 requirement R8 presently states: “The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds." In order for this requirement to have the desired effect of ensuring a Balancing Authority’s ACE value is refreshed and accurate as of every six seconds, the tie line metering data being sampled by each Balancing Authority must also be accurate and updated at least every six seconds. Therefore, the ISO recommends that the SAR include within its scope the requirement for ensuring the tie line meter data being relied on for the “data acquisition for and calculation of ACE” is updated at least every six seconds to match the required sampling frequency. The SDT agrees and has made the necessary modifications to thee requirement.
Duke Energy	Comments: Duke Energy thanks the Periodic Review Team for their efforts, and would like to express our support for the recommendations made. The following comments are suggestions for the standard drafting team’s consideration. General Comment re: BAL-005: Unless the Standard Drafting Team chooses to revise, a re-post of the red-lined version of the current BAL-005 is necessary so that it may accurately reflect the numbering of the original version. The SDT has elected to not provide a redline version of the present standard since the proposed standard is a complete re-writing of the current standard. The SDT is providing a Mapping Document so that an entity can see what the SDT is proposing to be done with the present requirements. Duke Energy agrees with the PRT’s recomendation that the NERC Glossary of Terms defintion of ACE and Reporting ACE should be reviewed. In addition, we agree that a comprehensive review of the NERC standards is necessary to ensure that any

Organization	Question 4 Comment
	updates/revsions to the NERC definitions mentioned above would not impact other NERC Reliability Standards. 1) Requirement 1: Duke Energy echoes the concerns of the Periodic Review Team in ensuring to keep responsibility of staying in a metered boundary with the LSE, TOP, and GOP. We do not agree with the possibility of placing this responsibility with the BA. The SDT agrees and has proposed to move this requirement to FAC-001. 2) Requirement 13: We agree with the approach suggested by the Periodic Review Team. Also, we support the development of a guideline document to further expand on the topic, and clarify any potential ambiguities that may exist. The SDT has moved this requirement into the proposed Requirements R1 and R7. 3) Requirement 14: Duke Energy is in agreement with the industry comments referenced by the Periodic Review Team for this requirement. If covered elsewhere, we feel that this requirement should be retired. The SDT disagrees with your comment. The SDT has moved this requirement into Requirements R5 and R8.
Exelon companies, BGE, ComEd, PECO	Exelon recognizes that this is a large Project. We appreciate the scope of the proposed changes and encourage the drafting team to be cautious so as to not re-assign obligations to other entities if requirements are “mapped” to other Standards. In general, Exelon agrees with the changes proposed in the SAR and to changes in the applicability, including the removal of the LSE. We note however, changes to LSE applicable requirements need to be considered in light of the RRB initiative. Exelon believes that applicability for R17 is solely to the Balancing Authority; we agree with the PRT recommendation that BAL-005 R17 be written to be specific to the equipment used to determine the frequency component required for reporting ACE as is detailed in the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17. See Appendix 1 which limits the requirement to BA frequency monitoring. The SDT thanks you for your comment and agrees.

Organization	Question 4 Comment
ISO Standards Review Committee	The general scope of the SAR is fine. The challenge is the SAR covers the entire scope recommended by the Periodic Review Team and also references a separate document. A SAR is intended to set the general bounds of a standard. Our approval of the SAR does not imply we agree with everything included. We strongly request that the previous comments submitted earlier in the year be addressed prior to substantive work. The SAR provides an outline of what could transpire during the development/revision of the proposed standard. The SDT will take your comment into consideration as it reviews the current standard.
SPP Standards Review Group	There were several documents (redlined standards, Consideration of Comments, directives and issues, IERP recommendations) mentioned in the Unofficial Comment Form which indicated they were included in this posting but they aren't on the project page. The SDT apologizes for this omission. However, the SDT has revised the standards in an equally effective and efficient manner than what was originally developed by the PRT.
DTE Electric Co.	We agree that R15 of BAL-005 belongs in EOP-008. The SDT thanks you for your comment.
ACES Standards Collaborators	We will provide specific comments on the proposed changes to the standards after the SAR is approved and the formal standards development process begins. Thank you for the opportunity to comment. The SDT thanks you for your comment.

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014

Anticipated Actions	Date
45-day formal comment period with parallel ballot	August/September 2015
Final ballot	October 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:

Automatic Generation Control (AGC): Centrally located equipment ~~Equipment~~ that automatically adjusts resources ~~generation~~ in a Balancing Authority Area ~~from a central location~~ to help maintain the Reporting ACE in that of a Balancing Authority~~'s~~ Area within the bounds required by applicable NERC Reliability Standards~~interchange schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~ Resources utilized under AGC may include, but are not limited to, conventional generation, variable energy resources, storage devices and loads acting as resources (such as Demand Response).

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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 Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between 0.2*|B_i| and L_{10}, 0.2*|B_i|≤ L_{max} ≤ L_{10} .
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- Y = B_i / B_S.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * 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: ΔTE = $TE_{end\ hour}$ – $TE_{begin\ hour}$ – 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.

- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Balancing Authority

    4.2. Facilities:

    4.2.1. N/A

Effective Date: See Implementation Plan

B. Requirements and Measures

Rationale for Requirement R1: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data (meaning data from the same source) is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action. The intent of Requirement R1 is to provide accuracy in the measurements and calculations used in Reporting ACE, hourly inadvertent energy, and Frequency Response measurements. It specifies the need for common metering points for instantaneous and hourly integrated values for the tie line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply when more than two Balancing Authorities participate in allocating shares of a generation resource or in supplementary regulation, for example.

R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed-upon time synchronized common source to determine hourly megawatt-hour values. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. These values shall be exchanged between Adjacent Balancing Authorities.

M1. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if the Balancing Authority and its adjacent Balancing Authority have agreed upon a time synchronized common source to determine megawatt-hour values.

Rationale for Requirement R2: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events which would degrade the operator's ability to maintain reliability.

R2. The Balancing Authority shall use a scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R3: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R3. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R4: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient

available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R4. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

4.1. that is available a minimum of 99.95% for each calendar year; and,

4.2. with a minimum accuracy of 0.001 Hz.

M4. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R4.

Rationale for Requirement R5: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R5. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M5. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R6: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R6. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R7: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

R7. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M7. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R7 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R8: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R8 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

R8. Each Balancing Authority shall agree with an Adjacent Balancing Authority on a common source for respective Tie-Lines, Pseudo-Ties, and Dynamic Schedules and shall implement that common source to provide common information to both Balancing Authorities for the calculation of Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if it agreed with its adjacent Balancing Authority on a common source for the components used in the calculation of Reporting ACE.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to agree upon a time synchronized common source for hourly megawatt hour values with its Adjacent Balancing Authorities Or The Balancing Authority failed to provide the megawatt hour values to its Adjacent Balancing Authorities.
R2.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.

R3.	**Real-time Operations**	**Medium**	**The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.**
R4.	**Real-time Operations**	**Medium**	**The Balancing Authority’s frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.**	**The Balancing Authority’s frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.**	**The Balancing Authority’s frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.**	**The Balancing Authority’s frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year** **Or** **The Balancing Authority’s frequency metering equipment used for the**

						calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R5.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with Reporting ACE to its operators.
R6.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R7.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing authority failed to implement an Operating Process to

						identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R8.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to agree upon a common source for tie-lines, Pseudo-ties and Dynamic Schedules with its Adjacent Balancing Authorities Or The Balancing Authority failed to implement the common source to provide common information to both Balancing Authorities.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

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

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

This is the first posting of the draft standard for a 45-day formal comment period.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014

Anticipated Actions	Date
45-day formal comment period with parallel ballot	August/September 2015
Final ballot	October 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: None

Introduction

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

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

   4.1. Balancing Authorities.
5. **Effective Date:** See Implementation Plan

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R3.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R3.1.1 The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R3.1.2 The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R3.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R3.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R3.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange.
R3.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R3.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R3.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R3.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R4.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following	N/A	N/A

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.		

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	April 6, 2006	Added following to “Effective Date:” This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver (Project 2009-18).	Revision
2	November 5, 2009	Approved by the Board of Trustees	
2	January 6, 2011	Approved by FERC	

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

This is the first posting of the draft standard for a 45-day formal comment period.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014

Anticipated Actions	Date
45-day formal comment period with parallel ballot	August/September 2015
Final ballot	October 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: None

Introduction

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

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

   4.1. Balancing Authorities.
5. **Effective Date:** See Implementation Plan

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

~~**R3.** Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)~~

~~**R4.**~~**R3.** Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

~~**R4.1.**~~**R3.1.** Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R3.1.1 The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R3.1.2 The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

~~**R4.2.**~~**R3.2.** Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

~~**R4.3.**~~**R3.3.** A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

~~**R5.**~~**R4.** Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
~~R3.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.~~
R3~~4~~.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R3~~4~~.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R3~~4~~.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R3~~4~~.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R3~~4~~.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R3~~4~~.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Interchange.
R4~~5~~.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver (Project 2009-18).	Revision
2	November 5, 2009	Approved by the Board of Trustees	
2	January 6, 2011	Approved by FERC	

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014

Anticipated Actions	Date
45-day formal comment period with parallel ballot	August/September 2015
Final ballot	October 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: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

   4.1.3 Load Serving Entities

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

R5. Each Transmission Owner with Transmission Facilities operating in an Interconnection shall confirm that each Transmission Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M5. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R5.

R6. Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M6. Each Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R6.

R7. Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M7. Each applicable Load Serving Entity shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R7.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner and applicable Generator Owner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	N/A	The Transmission Owner addressed either R3, Part 3.1 or Part 3.2 in its Facility interconnection requirements, but did not address both.	The Transmission Owner addressed neither R3, Part 3.1 nor Part 3.2 in its Facility interconnection requirements.
R4	Long-term Planning	Lower	N/A	N/A	The applicable Generator Owner addressed either R4, Part 4.1 or Part 4.2 in its Facility interconnection requirements, but did not address both.	The applicable Generator Owner addressed neither R4, Part 4.1 nor Part 4.2 in its Facility interconnection requirements.
R5	Long-term Planning	Medium	N/A	N/A	N/A	The Transmission Operator with Transmission Facilities operating in an Interconnection failed to ensure that those Transmission Facilities were included within metered boundaries of a Balancing Authority Area.

R6	Long-term Planning	Medium	N/A	N/A	N/A	The Generation Operator with generation Facilities operating in an Interconnection failed to ensure that those generation Facilities were included within metered boundaries of a Balancing Authority Area.
R7	Long-term Planning	Medium	N/A	N/A	N/A	The Load-Serving Entity with Load operating in an Interconnection failed to ensure that those Loads were included within metered boundaries of a Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
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NERC Board adoption	November 2015

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Term: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**
2. **Number:** FAC-001-~~2~~3
3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

   4.1.3 Load Serving Entities

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

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4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

R5. Each Transmission Owner with Transmission Facilities operating in an Interconnection shall confirm that each Transmission Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M5. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R5.

R6. Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M6. Each Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R6.

R7. Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*

M7. Each applicable Load Serving Entity shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R7.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
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R6	Long-term Planning	Medium	N/A	N/A	N/A	The Generation Operator with generation Facilities operating in an Interconnection failed to ensure that those generation Facilities were included within metered boundaries of a Balancing Authority Area.
R7	Long-term Planning	Medium	N/A	N/A	N/A	The Load-Serving Entity with Load operating in an Interconnection failed to ensure that those Loads were included within metered boundaries of a Balancing Authority Area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

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- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

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1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

Implementation Plan

Reliability Standard BAL-005-1

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction ($\mathbf{I_{ATEC}}$): 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.

$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(\mathbf{1}-Y)*\boldsymbol{H}}$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BA between 0.2*|B_i| and L_{10}, 0.2*|B_i|≤ L_{max} ≤ L_{10} .
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- 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.
- Y = B_i / B_S.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * 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: ΔTE = $TE_{end\ hour}$ – $TE_{begin\ hour}$ – 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): Centrally located equipment ~~Equipment~~ that automatically adjusts resources ~~generation~~ in a Balancing Authority Area ~~from a central location~~ to help maintain the Reporting ACE of a Balancing Authority~~'s~~ Area within the bounds required under the NERC Reliability Standards~~interchange schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~ Resources utilized under AGC may include, but not be limited to, conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-005-1 **will implemented concurrently with FAC-001-3,** as reflected in the "Prerequisite Approvals" section above.

Effective Dates

BAL-005-1 and associated definitions shall become effective on the first day of the first calendar quarter that is twelve 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 twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of Reporting ACE and Automatic Generation Control should be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

Implementation Plan

Reliability Standard BAL-006-3

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- BAL-006-3 – Inadvertent Interchange

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-3 will be implemented concurrently with BAL-005-1, as reflected in the "Prerequisite Approvals" section above.

Effective Dates

BAL-006-3 shall become effective on the effective date of BAL-005-1.

Retirements

BAL-006-2 (Inadvertent Interchange) shall be retired immediately prior to the Effective Date of BAL-006-3 (Inadvertent Interchange) in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Reliability Standard FAC-001-3

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- FAC-001-3 – Facility Interconnection Requirements

Requested Retirement

- FAC-001-2 – Facility Interconnection Requirements

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

Background

Reliability Standard FAC-001-3 addresses Facility Interconnection Requirements, which ensure the avoidance of adverse impacts on the reliability of the Bulk Electric System by requiring Transmission Owners and applicable Generator Owners to document and make Facility interconnection requirements available so that entities seeking to interconnect will have necessary information. Reliability Standard FAC-001-3 and associated Implementation Plan was developed in conjunction with BAL-005-1 (Balancing Authority Controls) to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented concurrently with BAL-005-1, as reflected in the "Prerequisite Approvals" section above.

Effective Dates

FAC-001-3 shall become effective on the effective date of BAL-005-1.

Retirements

FAC-001-2 (Facility Interconnection Requirements) shall be retired immediately prior to the Effective Date of FAC-001-3 (Facility Interconnection Requirements) in the particular jurisdiction in which the revised standard is becoming effective.

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014

Anticipated Actions	Date
45-day formal comment period with parallel ballot	August/September 2015
Final ballot	October 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:

Automatic Generation Control (AGC): Centrally located equipment ~~Equipment~~ that automatically adjusts resources ~~generation~~ in a Balancing Authority Area ~~from a central location~~ to help maintain the Reporting ACE in that of a Balancing Authority~~'s~~ Area within the bounds required by applicable NERC Reliability Standards~~interchange schedule plus Frequency Bias~~. ~~AGC may also accommodate automatic inadvertent payback and time error correction.~~ Resources utilized under AGC may include, but are not limited to, conventional generation, variable energy resources, storage devices and loads acting as resources (such as Demand Response).

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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 Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BA between 0.2*|B_i| and L_{10}, 0.2*|B_i|≤ L_{max} ≤ L_{10} .
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- Y = B_i / B_S.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * 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: ΔTE = $TE_{end\ hour}$ – $TE_{begin\ hour}$ – 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.

- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
   - **4.2. Facilities:**
     - **4.2.1.** N/A

Effective Date: See Implementation Plan

B. Requirements and Measures

> **Rationale for Requirement R1:** Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data (meaning data from the same source) is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.
>
> The intent of Requirement R1 is to provide accuracy in the measurements and calculations used in Reporting ACE, hourly inadvertent energy, and Frequency Response measurements. It specifies the need for common metering points for instantaneous and hourly integrated values for the tie line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply when more than two Balancing Authorities participate in allocating shares of a generation resource or in supplementary regulation, for example.

R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed-upon time synchronized common source to determine hourly megawatt-hour values. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. These values shall be exchanged between Adjacent Balancing Authorities.

M1. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if the Balancing Authority and its adjacent Balancing Authority have agreed upon a time synchronized common source to determine megawatt-hour values.

Rationale for Requirement R2: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events which would degrade the operator's ability to maintain reliability.

R2. The Balancing Authority shall use a scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R3: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R3. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R4: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient

available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R4. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

4.1. that is available a minimum of 99.95% for each calendar year; and,

4.2. with a minimum accuracy of 0.001 Hz.

M4. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R4.

Rationale for Requirement R5: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R5. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M5. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R6: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R6. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R7: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

R7. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M7. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R7 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R8: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R8 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

R8. Each Balancing Authority shall agree with an Adjacent Balancing Authority on a common source for respective Tie-Lines, Pseudo-Ties, and Dynamic Schedules and shall implement that common source to provide common information to both Balancing Authorities for the calculation of Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if it agreed with its adjacent Balancing Authority on a common source for the components used in the calculation of Reporting ACE.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to agree upon a time synchronized common source for hourly megawatt hour values with its Adjacent Balancing Authorities Or The Balancing Authority failed to provide the megawatt hour values to its Adjacent Balancing Authorities.
R2.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.

R3.	**Real-time Operations**	**Medium**	**The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an inability to calculate Reporting ACE.**	**The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.**
R4.	**Real-time Operations**	**Medium**	**The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.**	**The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.**	**The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.**	**The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year** **Or** **The Balancing Authority's frequency metering equipment used for the**

						calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R5.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with Reporting ACE to its operators.
R6.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R7.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing authority failed to implement an Operating Process to

						identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R8.	**Operations Planning**	**Medium**	**N/A**	**N/A**	**N/A**	**The Balancing Authority failed to agree upon a common source for tie-lines, Pseudo-ties and Dynamic Schedules with its Adjacent Balancing Authorities** **Or** **The Balancing Authority failed to implement the common source to provide common information to both Balancing Authorities.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

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.

Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	This Requirement has been moved into FAC-001-2 Requirement R5, R6 and R7	This requirement does not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R1 and Requirement R8.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R1 and Requirement R8.
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R1 and Requirement R8.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R3	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R3.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R2 and Part 8.1 was moved into Requirement R4	The body of this requirement has been moved to Requirement R2 and Part 8.1 has been moved into Requirement R4.
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R1 ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R1	This requirement has been moved to Requirement R1.
BAL-005-0.2b R13	Moved to Requirement R1 and Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R1. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R5 and Requirement R8	This requirement has been moved into Requirement R5 and Requirement R8.
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality.
BAL-005-0.2b R16	Moved to Requirement R5	This requirement has been moved into Requirement R5.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R4)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R4.

Project 2010-14.2.1 Mapping Document
Transition of BAL-006-2 to BAL-006-3

Standard: BAL-006-3 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	No change	No change
BAL-006-2 R2	No change	No change
BAL-006-2 R3	Moved to BAL-005-1 Requirement R1 and Requirement R8	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	No change	No change
BAL-006-2 R5	No change	No change

Project 2010-14.2.1 Mapping Document
Transition of FAC-001-2 to FAC-001-3

Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R5	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R6	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R7	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Introduction:

Tie Line Bias[1] (TLB) control has been used as the preferred control method in North America for 75 years. In the early 1950's the term Area Control Error (ACE) was developed for the specific implementation of coordinated Tie Line Bias control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE[2] in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary; reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the Bulk Electric System.

The following definitions are included in the NERC Glossary:

Definition:
Actual Frequency **F_A** **5/11/2015**
The Interconnection frequency measured in Hertz (Hz).

Definition:
Actual Net Interchange **NI_A** **5/11/2015**
The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, with all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange.

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1 Capitalized terms hold the same definition as in the NERC glossary throughout this document.

2 The CPS1 measure was among the first of the results based measures developed by NERC. It defined not how to perform control, but instead defined the target control results that were to be achieved, and a method to measure whether or not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, Area Control Error (ACE) has been used to describe many terms involved in TLB Control. Within a BAA's Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions in order to smooth the control signals; or, there may be additional "feed-forward" terms added to ACE in anticipation of future changes (e.g. anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting to improve the quality of control for the specific characteristics of that particular BAA.

Some auditors have raised compliance issue related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in BAL-001. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Definition:

Automatic Time Error Correction **I_{ATEC}** **5/11/2015**

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 (PII) to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

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

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$ **.**

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

- $\mathbf{L_{max}}$ is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- **Y** = B_i / B_S.
- **H** = Number of hours used to payback primary Inadvertent Interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- $\mathbf{B_S}$ = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange ($\mathbf{PII_{hourly}}$) is (1-Y) $*$ (II_{actual} – B_i $*$ ΔTE/6)
- $\mathbf{II_{actual}}$ 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: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- $\mathbf{TD_{adj}}$ 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.
- $\mathbf{TE_{offset}}$ is 0.000 or +0.020 or -0.020.
- $\mathbf{PII_{accum}}$ is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\mathrm{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathrm{PII}_{accum}^{on/offpeak} + \mathrm{PII}_{hourly}$$

Definition:

Frequency Bias Setting **B** **4/1/2015**

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority Area's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Definition:

Interchange Meter Error **I_{ME}** **5/11/2015**

A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Definition:

Reporting ACE **RACE** **5/11/2015**

The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Definition:
Scheduled Frequency **F_S** **3/16/2007**
60.0 Hz, except during a manual Time Error Correction.

Definition:
Scheduled Net Interchange **NI_S** **5/11/2015**
The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Structure:

The effective use of Reporting ACE within a TLB control program should address the following components:

(I) Management Roles and Expectations
(II) Information Technology Roles
(III) System Operator Roles
(IV) Manual Source Data Entry
(V) Automatically Collected Source Data
(VI) Uses of Reporting ACE
(VII) Historic Data Management
(VIII) Special Conditions and Calculations

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the Tie Line Bias control program.

Each responsible entity should evaluate all of its uses for Reporting ACE in its operations and its reliability measurement. Reporting ACE is one of the most important single measurements available to indicate the current state of the Responsible Entity's contribution to interconnection reliability.[3] Reporting ACE is also used as an integral part of the measurements used in BAL-001 and BAL-002. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in BAL-003 and BAL-005.

I. Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Tie Line Bias control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

a. Set expectations for safety, reliability, and operational performance.

[3] When configured with a Frequency Bias Setting equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match its actual interchange, less the impact from its current Frequency Response offset, to its scheduled interchange.

b. Assure that a TLB control program exists for each responsible entity and is current.
c. Provide annual training on the TLB control program and its purpose and requirements.
d. Ensure the proper expectation of TLB control program performance.
e. Share insights across industry associations.

II. Information Technology (IT) Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE and source information are always current and correct.
c. Implement the TLB control program in Real-time.
d. Ensure that the EMS supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.
e. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.
f. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the following calculations and equations:

1) Actual Net Interchange[4] (NI_A):

All BAAs involved account for the power exchange and associated transmission losses as actual interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout all of their energy accounting processes.

i. Calculate for each scan.[5]
ii. Integrated hourly average calculated for each hour as an integration of the scan rate values.

[4] By definition "Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.

[5] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

2) Scheduled Net Interchange[6] (NI_S):
   i. Calculate for each scan.
   ii. Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

   Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout all of their energy accounting processes.

3) Frequency Error ($\Delta F = (F_A - F_S)$):
   i. Calculate for each scan.
   ii. Calculate clock-minute average from valid samples available within each clock-minute[7] where at least half of the scan-rate samples are valid.

4) Frequency Trigger Limit – Low (FTL_{Low})[8]:

   Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

5) Frequency Trigger Limit – High (FTL_{High})[9]:

   Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

6) Accumulated primary Inadvertent Interchange (PII): Calculated each hour for WECC BAAs only.

$$\mathrm{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} = \boldsymbol{last\ period's}\ \mathrm{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} + \mathrm{PII}_{\boldsymbol{hourly}}$$

7) Automatic Time Error Correction (IATEC): Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

   $\mathrm{I}_{\mathbf{ATEC}} = \dfrac{\mathrm{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/off\ peak}}}{(\mathbf{1}-\boldsymbol{Y})*\boldsymbol{H}}$ when operating in ATEC mode.

   The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$ **.**

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

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[6] By definition "Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

[7] Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

[8] This variable could be entered manually as long as it is changed every time a manual time error correction is started or stopped. If manual time error correction is eliminated, it could become a constant and entered manually.

8) Reporting ACE:
   i. Calculate for each scan.
   ii. Calculated average for each clock-minute for BAAs using a fixed Frequency Bias Setting when at least half of the values are valid.[9]

9) Compliance Factor[10]:
   i. Calculate for each scan where both Reporting ACE and Frequency Error are valid.
   ii. Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[11]

10) Clock-hour compliance factor[8]:

    Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

11) Month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid clock-minute compliance factors in the month.

12) 12-month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

13) CPS1 compliance factor:

    Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the Epsilon_1 value for the Interconnection.

14) CPS1:
    i. Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.
    ii. Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.
    iii. Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2

[9] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid.

[10] Used for CPS1.

[11] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid and the average clock-minute Frequency Error is valid.

and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

iv. Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

v. Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

15) Balancing Authority ACE Limit - Low ($BAAL_{Low}$):

i. Calculate the scan rate Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

16) Balancing Authority ACE Limit - High ($BAAL_{High}$):

i. Calculate the scan rate Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

17) Balancing Authority ACE Limit - Low Compliance:

i. Alarm $BAAL_{Low}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$.

ii. Indicate $BAAL_{Low}$ non-compliance for each period where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$ for more than 30-consecutive clock-minutes.

18) Balancing Authority ACE Limit - High Compliance:

i. Alarm $BAAL_{High}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$.

ii. Indicate $BAAL_{High}$ non-compliance for each period where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$ for more than 30 consecutive clock minutes.

g. Ensure that the EMS supports the retention of all historic data including data quality information required to be retained to support continuing operations and audit requirements.

h. Ensure that the EMS supports and manages the presentation of all information required to be available to the System Operator for real-time operations, operations staff for evaluation of operations, and auditors for compliance confirmation.

i. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.

III. System Operator and Operations Staff Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE information is always current and correct.
c. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.
d. Implement the TLB control program in Real-time.

IV. Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[12], by the Responsible Entity's Energy Management System (EMS), and may be partially based on source data manually entered into that system. The following source data may be entered:

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent Balancing Authority Areas may not be available from an automatic collection source, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent Balancing Authority Areas entering the manual data. If the actual flow estimates are the same for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

NI_S (Scheduled Net Interchange): The power transfer schedules, including the schedule ramps where applicable, are processed by the EMS. If scheduled flow estimates are equal and have opposite signs for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The Frequency Bias Setting, or minimum required value, for the Balancing Authority Area is specified by calculations performed as part of compliance with BAL-003-1 - Frequency Response and Frequency Bias Setting;

R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area 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

[12] BAL-005-1 Balancing Authority Control - R2. The Balancing Authority shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE.

(ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.[13]

10 is the factor (10 0.1Hz/Hz) that converts the Frequency Bias Setting units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor as specified in BAL-004-0.[14] It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all times.

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for **I_{ATEC}** set by each BA between 0.2*|B| and L_{10}, $0.2*|B| \le L_{max} \le L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is normally set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum Frequency Bias Settings for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the interconnection.

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[13] As a note of interest, the new procedures put forth with BAL-003-1 will result in the reduction of minimum Frequency Bias Setting values on the multiple BA interconnections to bring them closer to the natural measured Frequency Response of the interconnection. The rule requiring a minimum Frequency Bias Setting of 1% of peak load in the NERC Standards dates back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response which was 2% of peak load at that time. The 1% figure is now more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid.

[14] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

V. Automatically Collected Source Data

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds[15], by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the System Operators. This data quality information is presented to the System Operator to have situational awareness with respect to the quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as CPS1, BAAL, DCS, and frequency response obligation (FRM).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[16,17,18,19] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the System Operator to support situational awareness.[20] The EMS sums the individual flow values on all tie lines and pseudo ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry element is passed to the result of all calculations using that element.

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent Balancing Authority Area, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent Balancing Authority Area for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005[21] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

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[15] BAL-005-1 Balancing Authority Control – "R2. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[16] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS. See the attached document titled "Anti-aliasing Filtering."

[17] It is acceptable to collect tie-line flow data from RTUs that use report by exception as long as those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[18] The six-second scan rate not only assures that data collected is close to Real-time, it also limits the latency (time skew) associated with the data collection.

[19] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[20] Indications of suspect data are usually indicated with color changes and/or alarms.

[21] BAL-005 – Automatic Generation Control specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the Digital Frequency Transducer.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange. (Block schedules are not used for this calculation.)

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

VI. Uses of Reporting ACE

a. Reporting ACE is currently used to measure secondary frequency control within TLB control on all of the Interconnections.[22] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing Standards. The following standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

   i. BAL-001-1 – Real Power Balancing Control Performance and BAL-001-2 – Real Power Balancing Control Performance.

   ii. BAL-002-1 – Disturbance Control Performance and BAL-002-2 – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved).

   iii. BAL-005-0.2b – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved).

   iv. BAL-006-2 Inadvertent Interchange.

b. The industry may also consider the use of Reporting ACE in the future to evaluate the rules associated with transmission loading.

VII. Historic Data Management

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and "TLB control program".

VIII. Special Conditions and Calculations

a. **I_{ME} (Interchange Meter Error)** This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation. It compensates for data or equipment errors affecting any other components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly agreed to accumulated meter data. The process used for including adjustments in the **I_{ME}** term should be based on good quality control methods.[23]

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[22] On single BAA Interconnections, the ACE Equation reduces to a single term, **$-10B\,(F_A - F_S)$**, because there are no tie lines or schedules to include in the first term, **$(NI_A - NI_S)$**, and there is no **I_{ME}** term to correct for tie line or dynamic schedule measurement errors in the first term.

[23] Adjustments to the **I_{ME}** term should follow good quality control methods and exclude tampering as demonstrated by the Deming's Funnel Experiment, http://blog.newsystemsthinking.com/w-edwards-deming-and-the-funnel-experiment/ .

The goal associated with the use of the $\mathbf{I_{ME}}$ is to encourage the scan-rate values of actual and scheduled interchange between Adjacent Balancing Authority Areas to be equal in magnitude and have opposite signs.[24] When initially configured, all BAAs used "Analog to Digital" converters and "Digital to Analog" converters to transmit tie-line flows from the common metering point required in the standards to the BAA's EMS. These "A to D" and "D to A" converters are subject to error and require frequent calibration, and although, many have been replaced by digital telemetry, they still exist and require oversight.

Management of the accuracy of the scan rate values used in the Reporting ACE equation can be accomplished by creating a process that compares the scan rate values to other values that have a greater likelihood of agreeing with the same values for the Adjacent BAA. Those values are adjusted as necessary using the $\mathbf{I_{ME}}$ term. Energy Management Systems are capable of integrating the scan rate values used for the calculation of Reporting ACE and providing those integrated values for comparison to the accumulated megawatt-hour values for the same meters. If the integrated scan rate values are close to the accumulated megawatt-hour values, then one can conclude that the scan rate values accurately represent the accumulated values. The final step in this process includes a comparison and agreement on the accumulated megawatt-hour values between the Adjacent BAAs sharing the measurement. This information used in conjunction with a similar analysis of the scan rate values for the same measurement by the Adjacent Balancing Authority Area including analysis of any differences between the accumulated values and the agreed to values. This total process provides reasonable assurance that the tie line flows or the dynamic schedules used by Adjacent BAAs are consistent with one another confining control problems within the boundaries of the Adjacent BAAs.

These error correction adjustments can be used to correct errors in the $\mathbf{NI_A}$ or $\mathbf{NI_S}$[25] terms for Reporting ACE and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the $\mathbf{I_{ME}}$ term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-1.

b. Use of Source-Sink Pairs for Asynchronous DC Tie Lines to Another Interconnection: One of the primary rules for insuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie lines, pseudo ties, interchange schedules and Dynamic Schedules to Adjacent Balancing Authority Areas and only Adjacent Balancing Authority Areas on the same Interconnection, and requiring the exclusion of all asynchronous DC tie lines and associated scheduled interchange with Balancing Authority Areas on a different Interconnection

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[24] As long as the tie line flows and scheduled flows match for Adjacent Balancing Authority Areas, any problems with the measurement of balancing on the interconnection will be confined to within the boundaries of those Adjacent Balancing Authority Areas.

[25] Errors in the $\mathbf{NI_S}$ would only occur and only support correction in cases where there is a measurement error associated with a Dynamic Schedule.

from Reporting ACE. Following this simple rule insures that all loads, losses and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie line bias control program. One terminal of an asynchronous DC tie line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie line will exclude the asynchronous tie line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

Standards Announcement Reminder

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-3, and FAC-001-3

Initial Ballot and Non-binding Poll Open through September 14, 2015

Now Available

An initial ballot for draft one of **BAL-005-1 –Balancing Authority Control, BAL-006-3 – Inadvertent Interchange, and FAC-001-3 – Facility Interconnection Requirements** and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern, Monday, September 14, 2015.**

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and associated VRFs and VSLs by clicking here.

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 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.

Standards Development Process

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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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-3, and FAC-001-3

Formal Comment Period Open through September 14, 2015
Ballot Pools Forming through August 28, 2015

Now Available

A 45-day formal comment period for draft one of **BAL-005-1 –Balancing Authority Control, BAL-006-3 – Inadvertent Interchange, and FAC-001-3 – Facility Interconnection Requirements** is open through **8 p.m. Eastern, Monday, September 14, 2015.**

Commenting

Use the electronic form to submit comments on the standards. 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, Friday, August 28, 2015**. Registered Ballot Body members may join the ballot pools here.

Next Steps

An initial ballot for the standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 4-14, 2015.**

Standards Development Process

For more information on the Standards Development Process, please refer to the Standard Processes Manual.

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Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
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An initial ballot for the standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 4-14, 2015.**

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Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1 and FAC-001-3

RSAWs Posted for Industry Comment through September 14, 2015

Now Available

The draft RSAWs for **BAL-005-1 – Balancing Authority Control and FAC-001-3 – Facility Interconnection Requirements** are posted on the project page for industry comment through **8 p.m. Eastern, Monday, September 14, 2015.** Submit feedback regarding the draft RSAWs to RSAWfeedback@nerc.net**.**

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 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-3, and FAC-001-3

Initial Ballot and Non-binding Poll Results

Now Available

A formal comment period and initial ballot for draft one of **BAL-005-1 –Balancing Authority Control, BAL-006-3 – Inadvertent Interchange, and FAC-001-3 – Facility Interconnection Requirements** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern, Monday, September 14, 2015.**

The initial ballot did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballot and non-binding poll.

Ballot	Non-binding Poll
Quorum /Approval	Quorum/Supportive Opinions
83.81% / 55.97%	83.64% / 56.90%

Next Steps

The drafting team will consider all comments received during the formal comment period, make revisions to the standards, and post them for an additional ballot.

Standards Development Process

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 (/SurveyResults/Index/27)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 IN 1 ST
Voting Start Date: 9/4/2015 12:01:00 AM
Voting End Date: 9/14/2015 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 264
Total Ballot Pool: 315
Quorum: 83.81
Weighted Segment Value: 55.97

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	78	1	37	0.627	22	0.373	0	7	12
Segment: 2	10	0.9	2	0.2	7	0.7	0	0	1
Segment: 3	72	1	33	0.611	21	0.389	0	3	15
Segment: 4	25	1	12	0.6	8	0.4	0	2	3
Segment: 5	72	1	31	0.585	22	0.415	0	6	13
Segment: 6	44	1	23	0.639	13	0.361	0	1	7
Segment: 7	2	0.1	1	0.1	0	0	0	1	0
Segment: 8	2	0.2	1	0.1	1	0.1	0	0	0

Segment: 9	2	0.1	0	0	1	0.1	0	1	0
Segment: 10	8	0.6	4	0.4	2	0.2	0	2	0
Totals:	315	6.9	144	3.862	97	3.038	0	23	51

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Negative	Third-Party Comments
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments

1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Shawna Speer		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		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	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Third-Party

					Comments
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Comments Submitted
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		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
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	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Abstain	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
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		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	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	Puget Sound Energy,	Theresa Rakowsky		Negative	Comments

	Inc.				Submitted
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		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A

1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
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	Third-Party Comments
2	Herb Schrayshuen	Herb Schrayshuen		Negative	Third-Party Comments
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted

3	BC Hydro and Power Authority	Pat Harrington		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Third-Party Comments
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
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		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Third-Party Comments
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		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	Mace Hunter		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Mike Anctil		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	None	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		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		None	N/A

3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		None	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
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	PNM Resources	Michael Mertz		None	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		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins	Chris Janick	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
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		None	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	Jim Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Affirmative	N/A
4	Austin Energy	Tina Garvey		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Third-Party Comments
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Third-Party Comments

4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Third-Party Comments
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Negative	Comments Submitted
4	Keys Energy Services	Stanley Rzad		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	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		None	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power	Steve McElhaney		None	N/A

	Association				
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	BC Hydro and Power Authority	Clement Ma		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Calpine Corporation	Hamid Zakery		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Independence,	Jim Nail		Affirmative	N/A

	Power and Light Department				
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		Affirmative	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	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	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		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Comments Submitted

5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Kenneth Silver		None	N/A
5	Lower Colorado River Authority	Dixie Wells		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		None	N/A
5	NextEra Energy	Allen Schriver		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Abstain	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee,	Karen Webb		Affirmative	N/A

	FL)				
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	Brandy Spraker		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc	Richard Hoag	Affirmative	N/A
6	Florida Municipal	Richard Montgomery		None	N/A

	Power Agency				
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lower Colorado River Authority	Michael Shaw		Affirmative	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	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Third-Party Comments
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		None	N/A
6	Platte River Power Authority	Carol Ballantine		Affirmative	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A

6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	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		Negative	Third-Party Comments
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	WEC Energy Group, Inc.	David Hathaway		None	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy		Negative	Comments Submitted
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Third-Party Comments
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Negative	Third-Party Comments
9	Commonwealth of Massachusetts	Donald Nelson		Abstain	N/A

	Department of Public Utilities				
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 315 of 315 entries

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/27)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 Non-binding Poll IN 1 NB
Voting Start Date: 9/4/2015 12:01:00 AM
Voting End Date: 9/14/2015 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 225
Total Ballot Pool: 269
Quorum: 83.64
Weighted Segment Value: 56.9

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	68	1	28	0.651	15	0.349	0	14	11
Segment: 2	8	0.6	1	0.1	5	0.5	0	2	0
Segment: 3	63	1	22	0.564	17	0.436	0	10	14
Segment: 4	20	1	8	0.533	7	0.467	0	3	2
Segment: 5	60	1	21	0.568	16	0.432	0	12	11
Segment: 6	37	1	15	0.577	11	0.423	0	5	6
Segment: 7	2	0.1	1	0.1	0	0	0	1	0
Segment: 8	1	0.1	0	0	1	0.1	0	0	0

Segment: 9	2	0.1	0	0	1	0.1	0	1	0
Segment: 10	8	0.5	3	0.3	2	0.2	0	3	0
Totals:	269	6.4	99	3.393	75	3.007	0	51	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	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		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A

1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Affirmative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
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		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Martin Boisvert		Negative	Comments Submitted

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		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	None	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	National Grid USA	Michael Jones		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	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Abstain	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A

1	Peak Reliability	Jared Shakespeare		Affirmative	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	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		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
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		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Negative	Comments Submitted
1	Southwest Transmission	John Shaver		Negative	Comments Submitted

	Cooperative, Inc.				
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Negative	Comments Submitted
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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		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		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren	David Jendras		Abstain	N/A

	Services				
3	Anaheim Public Utilities Dept.	Dennis Schmidt		Abstain	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lisa Martin		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		None	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Pat Harrington		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Negative	Comments Submitted
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
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		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A

3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Kent Kujala		Negative	Comments Submitted
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		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	Lakeland Electric	Mace Hunter		Negative	Comments Submitted
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A

3	MEAG Power	Roger Brand	Scott Miller	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		None	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Abstain	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	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		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Rachel Moore	Joe Tarantino	Affirmative	N/A
3	Salt River Project	John Coggins	Chris Janick	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A

3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Negative	Comments Submitted
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		None	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Affirmative	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		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Negative	Comments Submitted
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Negative	Comments Submitted
4	DTE Energy - Detroit Edison Company	Daniel Herring		Negative	Comments Submitted
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal	Carol Chinn		Negative	Comments

	Power Agency				Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		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		None	N/A
4	Sacramento Municipal Utility District	Michael Ramirez	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Abstain	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Negative	Comments Submitted
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		None	N/A

5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
5	BC Hydro and Power Authority	Clement Ma		Abstain	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Abstain	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Calpine Corporation	Hamid Zakery		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
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		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		None	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy -	Robert Loy		Affirmative	N/A

	FirstEnergy Solutions				
5	Florida Municipal Power Agency	David Schumann		Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	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		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	MEAG Power	Steven Grego	Scott Miller	None	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		None	N/A
5	NextEra Energy	Allen Schriver		Negative	Comments Submitted
5	NiSource - Northern Indiana Public	Michael Melvin		Negative	Comments Submitted

	Service Co.				
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Abstain	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	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		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Edward Magic		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Affirmative	N/A

5	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	Brandy Spraker		Abstain	N/A
5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	Mark Castagneri		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	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		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc	Richard Hoag	Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		None	N/A
6	Florida Municipal Power Pool	Tom Reedy		Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael	Negative	Comments

			Brytowski		Submitted
6	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		None	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		None	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
6	Platte River Power Authority	Carol Ballantine		Abstain	N/A
6	Portland General Electric Co.	Shawn Davis		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		None	N/A
6	Sacramento Municipal Utility District	Diane Clark	Joe Tarantino	Affirmative	N/A
6	Salt River Project	William Abraham	Chris Janick	Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	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		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Negative	Comments Submitted
6	Talen Energy Marketing, LLC	Elizabeth Davis		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Tiffany Lake		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		Abstain	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Negative	Comments Submitted
9	City of Vero Beach	Ginny Beigel		Negative	Comments Submitted
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	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		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Abstain	N/A
10	SERC Reliability Corporation	Joe Spencer		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity	Steven Rueckert		Abstain	N/A

	Coordinating Council				

Previous 1 Next

Showing 1 to 269 of 269 entries

Survey Report

Survey Details

Name 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-3 & FAC-001-3

Description

Start Date 7/30/2015

End Date 9/14/2015

Associated Ballots

2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 IN 1 ST

2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 Non-binding Poll IN 1 NB

Survey Questions

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

Yes

No

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

Yes

No

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3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

Yes

No

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

5. Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.

6. Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.

Responses By Question

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee for all questions in this Survey.

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: Yes

Answer Comment:

We agree it makes AGC more inclusive and understand there was a FERC directive to make this change, but the directive does not add to reliability.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 1 DTE Energy - Detroit Edison Company, 5, DePriest Jeffrey

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We agree that the modified definition is a step in the right direction. However, the definition references Demand Response in capital letters. While that concept is recognized by industry, it officially is not a NERC Glossary Term. We recommend that SDT rephrase the last sentence of this definition to read “Resources utilized under AGC may include, but not be limited to, conventional

	generation, variable energy resources, energy storage devices, and demand response resources.”
Document Name:	
Likes:	0
Dislikes:	0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE does agree that the revised definition is more inclusive. There is a concern, however, about disregarding asynchronous Tie MWs in the calculation for Reporting ACE. If a Balancing Authority (BA) has 1000 MWs of generation and 500 MWS of load with the remaining generation being transferred asynchronously, how will the ACE equation , and subsequently AGC, work properly?

With the revised definition of Reporting ACE, it appears the Standard Drafting Team (SDT) is disregarding single BA Interconnections, such as ERCOT and Quebec. Texas RE is concerned about the statement “All NERC Interconnections with multiple Balancing Authority Areas operate using the principles of Tie-bias (TLB) Control and requirement the use of an ACE equation similar to the Reporting ACE defined above.” This statement implies that single BA Interconnections, such as ERCOT and Quebec do not operate using the principles of TLB and the use of ACE. If not, how does BAL-001 apply? Is indicating an “alternative” method for a Reporting ACE equation use advocating regional differences?

Texas RE inquires as to whether it is the SDT’s intent that AGC (as currently defined in the proposed definition) will be only frequency-based for single-balancing authority areas.

Document Name:	
Likes:	0
Dislikes:	0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

FMPA supports using the term resources to make the definition more inclusive, but the capitalized term Demand Response is not in the NERC glossary of terms.

Document Name:

Likes:	0
Dislikes:	0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

PJM finds that the modified definition of AGC is inclusive of more resource types than only traditional generation resources. However, AGC equipment does not directly adjust the output of resources, but instead generates and sends control signals to the resources to change output. PJM suggests the following change to the definition for clarity:

Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjusts resources in a Balancing Authority Area to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. Resources utilized under AGC may include, but are not limited to, conventional generation, variable energy resources, storage devices and loads acting as resources (such as Demand Response).

Document Name:

Likes: 0

Dislikes: 0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer: Yes

Answer Comment:

AGC is no longer used in BAL-005-1, therefore HQ questions whether Project 2010-14.2.1 is the best opportunity to revise this definition.

Document Name:

Likes: 0

Dislikes: 0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

The modification is on the correct track to expand the definition.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy recommends that the drafting team clarify or state that just because a term appears in a definition does not make the definition applicable to said term. For example, the term *"Demand Response"* appears in the proposed definition of Automatic Generation Control (AGC), however, AGC does not adjust Demand Response. Clarification is needed from the drafting team stating that just because this term appears in the definition, this doesn't mean every type of Generating Resource, Load Resource, or Load reacting as a resource is capable of providing response to an AGC signal. Just because a term is listed in the definition, doesn't mean it should qualify as an example. We suggest the drafting team revise the language to include *"such as qualified demand resources"* rather than *"Demand Response"* which can mean a lot of different things.

Document Name:

Likes: 0

Dislikes: 0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer: No

Answer Comment:

These comments are submitted on behalf LG&E and KU Energy, LLC (LG&E/KU). LG&E/KU is registered in the SERC Region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, RP, TO, TOP, TP, and TSP

Comments:

Making a definition “more inclusive” does not make it clearer or better. In fact, an argument can be made that an “inclusive” definition can become problematic. The proposed definition includes uneccessary, prescriptive language on what types of resources may be used for AGC. We are concerned that the list will raise expectations that VERs, storage devices and Demand Response resources should be included in an entity’s AGC function. Many Demand Response programs (such as residential load interruption) are not compatible with AGC operations and should not be considered as such.

The last sentence of the proposed definition is not necessary, reduces the clarity of the definition and should be deleted.

Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjust resources in a Balancing Authority Area to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

The use of centrally located equipment, that automatically adjusts, maintain Reporting ACE, resources utilized under AGC needs to be considered.

There is no justification to link the definition of Automatic Generation Control (AGC) to a given location.

AGC is not hardware (equipment); AGC is software.

AGC does not "adjust resources" (that is usually accomplished at the resource itself). AGC "is used to adjust resources".

AGC is not designed for reporting purposes. AGC is design to assist in the control of a BA's balance of its resources to its NERC mandated balancing obligations.

Propose that the definition be revised to:

Automatic Generation Control (AGC): Software designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.

BAL-005 being a NERC standard and not one of the many regionally-approved standards is applicable to all BAs unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. Automatic Time Error Correction is not a part of the FERC-approved standards for all BAs. For clarity the regionally-approved definition and references to **Automatic Time Error Correction (I ATEC)** be deleted and left to an approved regional standard.

Document Name:

Likes:	0
Dislikes:	0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer: No

Answer Comment:

The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

See attached for the full text of the comments to Questions 1-6

Document Name:	SRC - 2010-14-2-1 BAL-005.006 FAC-001.docx
Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter

Shawna Speer

Segment

1

Entity

Colorado Springs Utilities

Region(s)

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2

Entity	Region(s)
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: No

Answer Comment:

The added sentence at the end of the definition adequately serves the purpose of clarifying that all “resources” are included rather than just traditional generators. The change to add the descriptor “Centrally located” when describing the “equipment” is also problematic. There does not appear to be a stated justification for making that change and it could introduce issues in interpretation surrounding redundant systems or sub-systems that could or should be included in the system that is used for AGC. If there is a reason for continuing to include the “centrally located” descriptor, we suggest that the SDT clarify the reason.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

We do not agree that FAC-001 is the correct standard to house these obligations. FAC-001 applies to the interconnection of new facilities, while the R5, R6 & R7 Requirements taken from BAL-005-0.2b apply to all Transmission, Generation & Load facilities.

In the event that the drafting team *is* successful in moving these obligations to FAC-001, the new requirements will need to be clarified so that the requirements apply only to new interconnecting facilities (consistent with the spirit of the other FAC-001 requirements). In that case, separate requirements will still be required elsewhere to apply to existing Transmission, Generation & Load facilities. In addition, it would also be incumbent on the TO to ensure that the wording for these obligations are explicit within their interconnect agreements and the necessary interconnect guides that are specified in FAC-001.

AEP's decision to vote negative on this proposal is driven by these objections.

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: No

Answer Comment:

It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

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

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:

See attachment with strikethrough.

It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

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

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

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

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

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Document Name: Project 2010-14..2.docx

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

It is not necessary to move this requirement. The requirement can be improved by keeping it where it is and limiting it to:

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

The requirement is a concept from the NERC Operating Manual (Control Area Criteria) that was swept into the V0 standard. There is only one way to prove that everything is within the metered bounds of a BA, that is through Inadvertent Interchange accounting. Thus the measure for this requirement should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

BAL-005-0.2b R1 should remain where it is, but would be improved by the removal of the sub Requirements. The only means to prove that everything is within the metered boudaries of a Balancing Authority is through Inadventent Interchange accounting.

The revised R1 should read: R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.
The measure M1 should read: M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model

	or tie lines that misstate its Nets Actual Interchange value in its Inadventent Interchange accounting.
Document Name:	
Likes:	0
Dislikes:	0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

While there is agreement with the removal of R1 from BAL-005-0.2b, the insertion of 4.1.3, and R5-R7 into FAC-001-2 is not required. Notification of an entities inclusion within a Balancing Authority's metered boundaries can be accomplished through the NERC Rules of Procedure, Section 500, FAC-001-2, proposed standard TOP-003-3 and existing standard IRO-010-2. For example, sufficient latitude exists within FAC-001-2 as approved, for the TO to provide notification to "those responsible for the reliability of the affected system(s) of new or materially modified existing interconnections." Through this requirement, the TO can provide a list of new or modified facilities (such as new or modified load, transmission and generator connections) to the TOP, BA and RC.

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: No

Answer Comment:

As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

1. We concur that the intent of BAL-005-0.2b Requirement R1 provides for identification of Interconnection Facilities and not for the calculation of Reporting ACE. We question if the SDT followed the recommendations of the Project 2010-14.2 BAL Standards PRT to “explore if the role of the TOP would appropriately cover the loads interconnected to that TOP

such that the LSE requirement may not be necessary." We ask the SDT to provide rationale for the proposed FAC-001-3 standard to explain their conclusion on why they continue to list the LSE as an applicable entity. We remind the SDT that the retirement of the LSE is pending FERC approval through the Risk-Based Registration (RBR) initiative. We do not understand why the SDT feels like the LSE has a reliability role, when the ERO continues to argue that the LSE is primarily focused on commercial activities and other entities, such as the TOP, would continue to meet reliability needs without the LSE. We strongly recommend that the drafting team remove the LSE from the applicability section.

2. As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real□time monitoring." If a BA needs information regarding a particular load, generation resource, or transmission line operating within its BA Area, based on this requirement, would they not "identify" the correct entity to send their specification? Furthermore, NERC has spent significant time and resources on the development of the BES definition and the removal of the LSE from its functional model. These efforts were accomplished to focus on entities and facilities that posed a significant risk to BES reliability. The SDT has already identified that the intent of these requirements is not for the calculation of Reporting ACE and only the identification of entities. Moreover, if a generation resource, transmission line, or load is not properly accounted for in the calculation of Reporting ACE, Inadvertent Interchange will result and the BA would investigate to correct the discrepancy, as a best practice, accordingly. We recommend the SDT remove these requirements from the proposed draft standards.

Document Name:

Likes: 0

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer: No

Answer Comment:

First, a quick review of the Standards shows there is no other specific requirement to ensure a facility is in a metered boundry or telemtery is provided to a RC, BA, or TOP. This requirement is to ensure that a load or generator is metered and communicated to BA for BA function. It is just as important that line metering is reported to TOP and RC, yet there is no FAC requirement to install metering and telemetry. For TOP and RC, there is TOP-03 and IRO-010 with a data specification and process to deliver data.

Second, FAC-001 is about developing a single document for one-time use by an interconnecting entity to know what is required to complete an interconnection. The proposed change creates an ongoing requirement to confoirm that the interconection is in the metered boundaries ofthe BA. The proposed requirement is not consistenent with FAC-001. A consistent approach to FAC-001 is to require that the requirements address the metering required to facilitate the BA function, but this is already impleied in the current FAC-001-2 standard.

Balancing is becoming a complicated function as compared to the Version 0 days. The BA should have its own data specification standard similar to TOP-003 or IRO-010. In the alternative these requirements should be retired, with the comment thatthe requirement is implied already in FAc-001-2 and the Technical and Guideline section of FAC-001-2 will be updated to include a specific explanation of including interconnection in BA metered boundary.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE noticed that the Load-Serving Entity (LSE) function was added to the FAC-001-3 applicability but is not mentioned in the Evidence Retention section.

Texas RE noticed the term, “Transmission Facilities” is capitalized in R5 but not in R1.2. The term “Transmission Facilities” is not a defined term in the NERC glossary so it could cause confusion if capitalized.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: No

Answer Comment:

Given the stongly suppported rationale for deactivating the LSE registration function under the Risk-Based Registration initiative, Requirement 1.3 of BAL-005-0.2b should not be moved to FAC-001-3 as Requirement 7. The necessity of retaining this language for reliability purposes should be reconsidered. [Has there ever been a situation where Load was not within a BA metered boundary?] If this language is needed for reliability, an alternate functional entity should be identified.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

Ameren supports MISO's comments for this question

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer: No

Answer Comment:

FMPA believes these requirements should be retired on the basis that they are covered by the data specification requirements of Board approved TOP-003-3. While it may be appropriate to include the concept of meters and BA metered boundaries in Facility interconnection requirements, as currently worded the proposed requirements do not fit with the purpose or applicability of FAC-001.

Document Name:	
Likes:	0
Dislikes:	0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

With moving BAL-005-0.2b R1 to FAC-001 R5 and R6, the requirement has shifted from being a Generator and Transmission Operator function to a Generator and Transmission Owner function. PJM questions and considers consequences with this change. PJM seeks clarity on the following topics:

Generation Owners, Transmission Owners, and Load-Serving Entities have no requirement to supply the Balancing Authority with data that affects the ACE calculation. PJM proposes the following changes to FAC-001 R5, R6, and R7:

R5. Each Transmission Owner with transmission Facilities operating in an Interconnection shall confirm that each transmission Facility is within a Balancing Authority Area’s metered boundaries. The Transmission Owner shall coordinate any changes caused to the ACE due to each transmission Facility with the impacted Balancing Authorities.
R6. Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area’s metered boundaries. The Generation Owner shall coordinate any changes caused to the ACE due to each generation Facility with impacted Balancing Authorities.
R7. Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area’s metered boundaries. The Load-Serving Entity shall coordinate changes caused to the ACE due to each Load with impacted Balancing Authorities.

Since Reporting ACE is made up of many components, including Net Actual Interchange (NIA), Balancing Authorities will be dependent on the Generator Owners, Transmission Owners, and Load-Serving Entities for this data. When

	ACE is impacted by the identified Interconnection Facilities, how should Reporting ACE be addressed by the Balancing Authority or Reliability Coordinator? If a Generator, Transmission Owner, or load-Serving Entity fail to confirm that each of their Facilities are within the Balancing Authority Area's metered boundaries, is the affected Balancing Authority responsible for calculating an accurate Reporting ACE? What effects will this have on R5? Will the Balancing Authority be aware data from the Generator Owner or Transmission Owner are missing or invalid if the Generator Owner or Transmission Owner have not confirmed it?
Document Name:	
Likes:	0
Dislikes:	0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer: No

Answer Comment:

FAC-001 is about Facility Interconnection Requirements. In the application guidelines of FAC-001-2, it is mentioned that these requirements include metering and telecommunications and as such could be interpreted to already include a requirement of metering to the BA. Meeting of facility interconnection requirements however is the purpose of FAC-002-1.

Therefore 2 options are available:

1. Modify the purpose of FAC-001 to include the GO, TO and LSE,DP or end-user meeting with facility interconnection requirements (whereas presently the purpose is only to make these requirements available) and add in section B, requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in R1 thru R4 (not only with the requirement of being within a BA's metered boundaries as is the case with Project 2010-14.2.1 proposal). Revise purpose of FAC-002-1 so that it addresses coordination studies rather than meeting facility connection and performance requirements.
2. Change the title of FAC-002 which presently is a bit at odds with its purpose and add requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in FAC-001.

Document Name:

Likes: 0

Dislikes: 0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: No

Answer Comment:

As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy requests further clarification on how the drafting team anticipates an entity will be required to demonstrate compliance with R5. As written, it does not appear that the proposed Requirements and Measures are in alignment. Currently, the requirements state that an entity (TO, GO, LSE) must confirm that a Facility is within a Balancing Authority Area's Metered Boundary, however, the measure suggests that an entity should point to a procedure to demonstrate compliance with R5, R6, and R7. We suggest that the drafting team revise the Measures to better align with what is being asked in the requirements, perhaps stating that an attestation letter from the BA would be adequate to demonstrate confirmation that an entity's Facility is within a BA Area's Metered Boundary.

Document Name:

Likes: 0

Dislikes: 0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Answer Comment:

As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: No

Answer Comment:

KCP&L believes moving BAL-005-02.b R1 to FAC-001 should be rejected; it is an attempt to shoe-horn Requirements into an unrelated Standard, or, at best, marginally related Standard.

The FAC-001 Standard relates to entities seeking to interconnect with the Bulk Electric System. The Proposed FAC-001-3 and its predecessor versions' Purpose declaration state, "To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information."

It is unclear how Transmission Owners, Generation Owners, and Load-Serving Entities confirming they are within a Balancing Authority's metered boundaries relate to Generator Owners seeking interconnection with the Bulk Electric System. The FAC-001 Standard relates to new equipment planned to interconnect with the Bulk Electric System while BAL-005-02.b R1 relates to current and operational interconnections.

Additionally, the SAR discusses moving the TOP, LSE, and GOP from BAL-005-02.b (See SAR, pp. 4-5) to the FAC Standards. It is unclear where the TOP duties under R1 landed. It didn't land in FAC-001. Granted, the SAR is a framework and not binding, the language suggests the SDT was uncertain where to "put" the R1 Requirement. However, the Proposed FAC-001-3 R5 Violation Severity Level states, "The Transmission Operators with Transmission Facilities operating in an Interconnection…" In consideration of the VSL language and the proposed FAC-001-3 not expressly applicable to Transmission Operators, KCP&L is concerned that moving BAL-005-02.b R1 to FAC-001, creates an unstated duty for Transmission Operators.

Furthermore, the Proposed FAC-001-3 Purpose declaration is reiterated in Applicability Sec. 4.1.2.1., "Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system."

The FAC-001 Standard relates to new interconnects to the Bulk Electric System and should not be used as a landing pad for BAL-005 Requirements that no longer are relevant to BAL-005. KCP&L does not object to moving BAL-005 R1 to another Standard, but FAC-001 is not the appropriate Standard and the proposed changes should be reconsidered.

Finally, in the event the changes to FAC-001-3 R5, R6, and R7 are endorsed by the stakeholders, KCP&L would ask language be added to FAC-001-3 to highlight it is applicable to new facilities, including the facilities identified in R5, R6, and R7.

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment:

We agree with moving BAL-005-0.2b Requirement R1 to FAC-001 standard. However, given the likely retirement of the LSE functional role consideration should be given in the SAR to making the requirement applicable to the DP functional entity role.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

Load Serving Entity (LSE) function: NERC provided FERC with justification to retire BAL-005-0.2b Part R1.3 for the LSE function (LSE function deregistration). Adding LSE requirements to FAC-001 does not appear to align with NERC's justification and the intent to retire BAL-005-0.2b R1.3.

FAC-001 Table of Compliance Elements: R5 and R6 reference Transmission Operator and Generation Operator, instead of Transmission Owner and Generator Owner.

The Purpose of FAC-001 is to "…make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information." Adding requirements to FAC-001 regarding metered boundaries appears to be misplaced. The proposed additions are ongoing requirements to confirm the metering of transmission facilities. The use of the word "confirm" is not the same as to establish the interconnection requirements.

Document Name:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer: No

Answer Comment:

(1) FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC -001 were removed including a requirement for metering and telecommunication.

Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R5, R6 and R7) does not resolve or address a reliability concern and would violate paragraph 81 criteria.

Moreover GTC believe that requirements FAC-001-3-R5, R6 and R7 address specific needs for operating the system and therefore belong and already are included in Operations Standards such as TOP and IRO and not a Planning Standard associated with Facility interconnection Requirements.

(2) As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real□time monitoring." TOP-003-3 applies to the same entities listed in the draft requirements.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer: No

Answer Comment:

The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

See file attached to Question 1 for the full text of the comments to Question 2

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter	Segment
Shawna Speer	1
Entity	**Region(s)**
Colorado Springs Utilities	

Selected Answer: No

Answer Comment:

The FAC-001 standard is used to facilitate interconnection requirements for those **entities seeking interconnection** into the **BES.** In the draft FAC-001-3 Requirements R5-R7 the language speaks to those who entities who are already operating in an interconnection and therefore does not fit the purpose of this standard. The FAC-001 standard cannot be used to enforce R5 –R7 for those facilities that already exist.

The LSE function should not be included in the FAC-001 standard and therefore R7 should be removed in its entirety from the draft. In R7, it is not clear if the LSE, TO, or GO will be required to address this in their interconnection requirements. There is no requirement for an LSE to have documented facility interconnection requirements.

To truly make this consistent with the purpose of the FAC-001 standard the wording should be revised to address the documented facility interconnection requirements. The draft standard should require that the TO & Applicable GO facility interconnection requirements address BAA metered bounds for those entities seeking interconnection. The entities seeking interconnection should determine their operating area and therefore BAA metered bounds from their desired interconnection location.

CSU is of the opinion that these requirements belong in the INT or TOP family of Standards.

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: No

Answer Comment:

These requirements do not rise to the level of needing a continuously audited Reliability Standard. Once a facility is interconnected and certified, then the inclusion within a BA's metered bounds should be verified at that time. There should not be a need for continuing certification that it remains within the metered bounds. The requirements as stated only result in administrative efforts and are an exercise in submitting attestations.

One suggestion would be to simply add a sub-requirement that the Transmission Owner's Interconnection Requirements (FAC-001-3 R1) must include a requirement that all interconnected facilities must be demonstrated to be within a Balancing Authority's metered boundaries. Then there would be no need for the new, proposed R5-R7. This puts the compliance effort into ensuring the facility is metered properly upon interconnection – to satisfy the TO Facility Interconnection Requirements – rather than an ongoing verification that the facilities continue to be within the metered bounds.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: No

Answer Comment:

Reclamation recommends that the drafting team propose to retire BAL-005-0.2b R1 instead of moving the requirement into FAC-001-3. Reclamation does not believe that the drafting team has addressed the Periodic Review Team's recommendation to identify "what is needed for ensuring facilities are within a Balancing Authority Area prior to MW being generated or consumed." Like the existing requirement, the proposed requirement does not mention verifying that facilities are within the metered boundaries of a Balancing Authority Area "prior to transmission operation, resource operation, or load being served." Therefore, the proposed requirement perpetuates a paperwork burden that costs staff time and resources of Generator Operators, Transmission Operators, and Load Serving Entities with longstanding arrangements with their host Balancing Authority. Registered Entities acquiring letters to confirm that they are in the metered boundaries of a Balancing Authority Area provides no benefit to system reliability.

Document Name:

Likes: 0

Dislikes: 0

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity’s ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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: No

Answer Comment:

MWHr meters are for Inadvertent Interchange accounting. Making this change will confuse the issue and will add unnecessary obligations. As long as the two BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole.

Document Name:

Likes: 0

Dislikes: 0

Terry Bllke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

MWHr meters are for Inadvertent Interchange accounting. There are already other requirements proposed that deal with making sure ACE is realatively accurate. Additionally, as long as adjacent BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

MWHr meters are for Inadventent Interchange accounting. Making the proposed change could lead to confustion and unnecessary obligations. If the two BAs use common metering, any minor error in ACE reporting is contained and would have no impact on the Interconnection as a whole.

Document Name:

Likes: 0

Dislikes: 0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We concur with the SDT’s recommendation, as BAL-005-1 addresses more proactive and real-time AGC operations while BAL-006 addresses more after-the-fact.

Document Name:	
Likes:	0
Dislikes:	0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE noticed there is no redline for BAL-005-1. Redlines are helpful in reviewing revisions.

Texas RE noticed BAL-006-2 R3 has the phrase "with readings provided ***hourly***" (emphasis added) which, dictates a timing aspect. BAL-005-1 R1 has the phrase "to determine hourly megawatt-hour values" but does not have a time aspect specifically required. Texas RE inquires whether this was the intent of the SDT (and Texas RE is aware of the expected historical practice of hourly communications between entities).

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

Ameren supports MISO's comments for this question

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

FMPA agrees removing R3 from BAL-006, but it seems to have created duplicative requirements in BAL-005. Requirements R1 and R8 should be combined.

Document Name:

Likes:	0
Dislikes:	0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

The standard states that the purpose is for acquiring data to calculate Reporting ACE. R1 does not fall under that category as it is currently written. It states its purpose is to determine MWh values. PJM suggests the following change to the R1 to align with the purpose of BAL-005:

R1. Each Balancing Authority shall ensure that each Tie Line, Pseudo Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed upon time synchronized common source. to determine hourly megawatt hour values.

While PJM agrees it is important to maintain a requirement to calculate MWh values for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer: No

Answer Comment:

For the Quebec Interconnection, it makes more sense for metering issues to be in BAL-006 than BAL-005 since as a single BA asynchronous Interconnection, Net Interchanges are not calculated in our ACE. However HQ understands that our situation is exceptional and do not oppose the move of BAL-006-2 R3 to BAL-005-1.

Document Name:

Likes: 0

Dislikes: 0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy agrees with the move to BAL-005-1, however, we recommend that the drafting team revise the Measure for R1 to better align with R1.1. The sub-requirement R1.1 states that megawatt-hour values must be exchanged between Adjacent Balancing Authorities. The Measure provides guidance for R1, but does not provide guidance or example of demonstrating compliance with R1.1. More information is needed to outline how an entity is expected to demonstrate that the exchange of values took place, and how often must the exchange take place.

Document Name:

Likes: 0

Dislikes: 0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: No

Answer Comment:

BAL-006-2--

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

Is there a requirement for hourly reporting? What is meant by "common"? Is this a certification issue, or an Interconnection Agreement issue, or a standard?

Document Name:

Likes: 0

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer: No

Answer Comment:

The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

See file attached to Question 1 for the full text of the comments to Question 3

Document Name:

Likes: 0

Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter

Shawna Speer

Segment

1

Entity

Colorado Springs Utilities

Region(s)

Selected Answer:

Answer Comment:

N/A

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

The change from BAL-006-2 R3 to BAL-005-1 R1 and R8 seem to be a step in the right direction. The measures however (BAL-005-1 M1) seems to only require evidence that a common source was agreed upon, not that the data values were actually exchanged between Adjacent BA's in a timely manner. If the intent is only to ensure a common source was identified, then that should be done in certification and does not rise to a Reliability Standard.

The need for common megawatt-hour meters between BAs serves only to account for inadvertent interchange between those entities. Accumulated inadvertent is not related to real-time reliability. Proposed BAL-005-1 R1 should be removed.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

a. Notwithstanding our comments on selected requirements provided below, as an overall comment we do not believe some of the proposed requirements belong to a Reliability Standard. We believe Requirements R2, R4, R5 and R6 are more suited for inclusion in the Organization Certification Requirement for Balancing Authorities since these requirements stipulate the capabilities and facilities that need to be in place to enable a BA to perform its tasks. These are "one-off" requirements that do not drive continuous behaviors, and they do not require frequent updates.

b. Requirement R4: The 99.95% uptime is overly prescriptive and there does not exist any technical justification. Unless supported by technical justification, this requirement should be removed. Further addition, the 0.001 Hz “accuracy” requirement is misleading. We suggest to replace "accuracy" with "resolution" to more properly convey the requirement.

c. Requirement R5: We agree with the need to provide operating personnel with accurate information that supports awareness and calculation of Reportable ACE, but the examples listed places emphasis on the secondary information as it fails to capture the more important pieces of information which were listed in the existing BAL-005. We therefore suggest R5 be revised to:

R5. The Balancing Authority shall make available to the operator information associated

with Reporting ACE including, but not limited to, real-time values for ACE, Interconnection

frequency, Net Actual Interchange with each Adjacent Balancing Authority Area and quality flags indicating missing or invalid data.

d. R6: As with our comments on R4, the 99.5% uptime is overly prescriptive and restrictive, and there does not exist any technical justification. A 99.5% uptime requirement means that all model builds and software glitches couldn’t exceed 43.8 hours in any given year. This is overly restrictive. Unless supported by technical justification, this requirement should be removed.

e. R7: This requirement is not needed. R1 already stipulates the need to calculate and hourly megawatt□hour values (and Reporting ACE, as we

suggested above); and R4 already stipulates the scan rate. Failure to meet either requirement will result in a BA being unable to comply with the standard in which case the BA must develop corrective actions to return to compliance. Having an explicit operating process to identify and mitigate errors affecting the scan rate accuracy of data used in the calculation of Reporting ACE is redundant to the combined requirements in R1 and R4. We therefore suggest to remove R7.

If for whatever reasons R7 is retained, then the term “Operating Process” should not be capitalized since it is not a NERC defined term.

f. R8: This requirement is implied in and redundant with, R1. Suggest to remove it.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:

See attachment with Strikethrough

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time sychnronized". AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall *ensure* **that have a process to operate to common, accurate** *each* **Tie Lines, Pseudo Ties, and Dynamic Schedules with its** *an* **Adjacent Balancing Authorities**. *is equipped with a mutually agreed upon time synchronized common source to determine hourly megawatt hour values*

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Document Name: Project 2010-14..4.pdf

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

The proposed R1 should be shortened and merged with R7. There need not be mention of “mutually agreed upon” nor “time sychnronized”. AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall have a process to operate to common, accurate Tie□Lines, Pseudo□Ties, and Dynamic Schedules with its Adjacent Balancing Authorities.

The measure of this requirement should not be logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

The proposed R1 should be shortened and merged with R7. No mention of “mutually agreed upon” nor “time sychnronized” is necessary. AGC and ACE use real-time values, not hourly values.

We suggest the following:

BAL-005-1
R1. Each Balancing Authority shall have a process to operate to common,

accurate Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its Adjacent Balancing Authorities.

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1.

R7 would not be necessary if the change to R1 above is made and R8 would be redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Document Name:

Likes: 0

Dislikes: 0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer:

Answer Comment:

No comments.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter

Brian Van Gheem

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer:

Answer Comment:

1. We believe Requirement R1 should focus on detection and correction of a problem rather than a guarantee that a common source is available. This would better align with a risk-based approach that NERC is mandating during standard development. We believe this can be achieved by rephrasing the requirement to read

"Each Balancing Authority shall monitor mutually agreed-upon time-synchronized common source with Adjacent Balancing Authorities to determine hourly megawatthour values for each common Tie Line, PseudoTie, and Dynamic Schedule." We feel that by moving in this direction, the associated VSLs can be set to more adjustable criteria, such as the length of time between detection and correction, (e.g. under 30, 60, and 90 days).

2. We feel the SDT should align the VSLs for R2 to more performance-based criteria. We agree that six-seconds is a reasonable benchmark, but question if it needs to be categorized as a severe VSL. Instead, we recommend assigning a sliding time scale to each VSL (e.g. greater than or equal to 6 seconds, and greater than or equal to 12 seconds, etc.)
3. In Requirement R3, the BA is expected to notify its RC within 45 minutes from the beginning of its inability to calculate Reporting ACE. If a BA encounters multiple instances when it is unable to calculate its Reporting ACE in a consecutive minute time period, but never haves an instance that is greater than thirty consecutive minutes, we want to confirm that the time period for notification begins with the first reportable instance. We believe this can be accomplished by replacing "an inability" with "the inability" at end of the requirement to read "…within 45 minutes of the beginning of the inability to calculate Reporting ACE."
4. We believe System Operators should be identified in Requirement R5, as this is a NERC-defined Glossary Term. Moreover, it does not provide any ambiguity for auditors and better aligns with those personnel identified to complete training for reliability-related tasks in Reliability Standard PER-005-2.
5. For Requirement R5, we agree with the SDT's approach that Reporting ACE can be a primary metric to determine operating actions or instructions. Furthermore, System Operators should be aware of when such metrics are based on poor or insufficient data. However, we disagree with the SDT's approach taken in the wording of this requirement. Proof of the existence of a graphical display or dated alarm log, as mentioned as possible evidence for compliance, will only lead to confusion on how evidence should be presented. We believe rewording this requirement to "each Balancing Authority shall monitor the quality of information used to calculate its own Reporting ACE" achieves the intent of "making available" sufficient data to System Operators.
6. We feel the SDT should provide rationale on the need for Requirement R6. While we agree that "Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection," we believe a requirement measuring the availability of a Reporting ACE calculation system is unnecessary. System Operators, when in distress, likely will rely on frequency meter measurements and communications with other Adjacent BAs when Reporting ACE is not available. This proposed standard already has an availability requirement listed in Requirement R4, and with a requirement that has a higher availability rate. We believe

requiring a system be available should be reserved for the ERO Event Analysis Process, much like SCADA is for RCs and TOPs.

7. We believe the VSLs criteria for Requirement R7 could be more performance-based, particularly with how fast the BA took to mitigate errors affecting the scan□rate accuracy of data. We recommend sliding scale criteria, such as within 15 minutes, within 30 minutes, etc.
8. In Requirement R8, we believe the requirement should focus on detection and correction to better align with a risk-based approach. We believe this can be achieved by rephrasing the requirement to read “Each Balancing Authority shall use a common source for Tie□Lines, Pseudo-Ties, and Dynamic Schedules with Adjacent Balancing Authorities when calculating Reporting ACE.” We feel that by moving the requirement in this direction, the associated VSLs can be set to adjustable criteria, such as the length of time between detection and correction, i.e. under 15 minutes, under 30 minutes, etc.
9. The data retention of the proposed standard, current year plus three years, is significantly larger than the one year retention found in the current standard and goes beyond the three-year audit cycle for BAs. In the context of a Risk-Based CMEP, we feel an entity should only need to retain one year’s worth of data. There is minimal reliability benefit to requiring an entity to store data for longer than one year, especially considering the tools in place for the ERO to spot check or self-certify compliance activities more frequently than an audit.
10. We believe the Implementation Plan should be updated to account for the retirement of IRO-005-3.1a, as Requirement R1.6 of that standard has the RC monitoring ACE and not Reportable ACE for all its BAs.
11. The third bullet of the proposed definition for Automatic Time Error Correction, as listed within the Implementation Plan, has a typographical error and should reference ε10.

Document Name:

Likes: 0

Dislikes: 0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

As stated in the answer to Question 1, Texas RE is concerned the SDT has not considered interconnections with a single BA. The initial SAR comments included the following statement: "Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception." It does not appear the SDT addressed the single-BA issue which results in the Reliability Standard not being applicable to the ERCOT and Quebec Interconnections. This, in turn, affects BAL-001 applicability. If Reporting ACE is not applicable to interconnections with a single BA, BAL-001 might not apply to the ERCOT and Quebec Interconnections. Additionally, any BA that connects with the ERCOT Interconnection BA will not be able to accurately determine Reporting ACE which could cause failure of BAL-001 for those BAs (assuming they utilize net interchange values in their Reporting ACE). This omission creates a reliability gap. Texas RE recommends including Interconnections with a single BA.

There seems to be some inconsistency with regards to definitions. For example, the definition of "Reporting ACE" in the Standard is different than the NERC Glossary of Terms (Glossary) but there is no redline. The definition of "AGC" is different from the Glossary and there is a redline. Is intent of the SDT to change both terms in the Glossary? Frequency Bias Setting is not defined within this Standard so it appears there is no change to that term. Asynchronous Ties should be included in the derivation of ACE where applicable. Without it, Reporting ACE will be off by the magnitude frequency applicable to the flows across a DC tie (especially if a trip of the DC occurs or an error in scheduling).

Texas RE noticed the term "adjacent" is not capitalized in M1. Texas RE recommends removing "its" when describing "Adjacent Balancing Authority" as there could be more than one Adjacent Balancing Authority in M1.

To make R5 consistent with the Purpose statement, Texas RE recommends changing "operator" to System Operator to be clear on which "operator" the information shall be made available. This change should also take place in the VSL for R5.

Per the comment in Question 1, R7 should be for all BAs not just BAs "within a multiple Balancing Authority Interconnection". R7 should only be relevant to the area of the Balancing Authority that is implementing an Operating Process.

Texas RE noticed the VSL for R1 does not include language should include language for each Tie Line, Pseudo-Tie or Dynamic Schedule to *be equipped* with an agreed upon source to determine values. As is, the VSL ignores the "equipped" language within the Standard.

Texas RE noticed the VSL language for R3 does not include "for 30 consecutive minutes". Should there be a dash in "30-consecutive" in Requirement 3?

Texas RE recommends changing the verbiage from "each calendar year" to "annually" or for "each rolling 12 month period". Specifically, R4 and R6 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the Evidence Retention statements. Texas RE would like the SDT consider whether this violates the RoP Appendix 4C Section 3.1.4.2 **Period Covered** "The audit period will not begin prior to the End Date of the previous Compliance Audit."? Morever, does it cause a gap in compliance monitoring (and reflect a possible gap in reliability)?

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment: **Ameren supports MISO's comments for this question**

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer:

Answer Comment:

FMPA disagrees with the use of the term “accuracy” in R4.2. We believe the intent would be better described by the term “precision”, or perhaps “degree of accuracy”.

FMPA does not find any technical justification for the 99.5% availability requirement in R6, and believes it may be duplicative with BAL-001 and present a double jeopardy issue.

Document Name:

Likes: 0

Dislikes: 0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Proposed Standard:
Located in BAL-005-1 R1:
R1. Each Balancing Authority shall ensure that each Tie□Line, Pseudo□Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed□ upon time synchronized common source to determine hourly megawatt□hour values.
1.1. These values shall be exchanged between Adjacent Balancing Authorities.

The phrase “Tie-Line” is not listed in the NERC Glossary, but instead “Tie Line” is listed.
Definition:
o Tie Line:
• A circuit connecting two Balancing Authority Areas.

The definition of “Pseudo-Tie” should be updated to include Reporting ACE if that is the purpose of the BAL-005-1 R1.
Definition:
o Pseudo-Tie:
• A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes).

If the SDT chooses not to change the language for R1, the language in R1.1 should be modified. With the current langauge the purpose of R1.1 is to exchange the hourly megawatt□hour values with the appropriate Balancing Authority to determine billing and Inadvertent Interchange. This should be stated more clearly as the current requirement has it written that the values are shared with [any] Adjacent Balancing Authority.

PJM proposes the following R1.1:
1.1. These values shall be exchanged for each Tie Line, Pseudo□Tie, and Dynamic Schedule shared between affected Balancing Authorities.

Document Name:

Likes: 0

Dislikes: 0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:

Answer Comment:

- In the Mapping Document for BAL-005-1, R9, there appears to be a contradiction in the Description and Change Justification section about the HVDC links and their inclusion or not in Reporting ACE calculation vs the definitions of Scheduled and Actual Net Interchanges that exclude asynchronous DC tie-lines directly connected to another interconnection.
- R1 vs R8: HQ faila to see the difference between the 2 requirements. Perhaps the Rationales should be enhanced for a better understanding.
- M1 and M8 do not seem appropriate measures for an agreement on common metering or other sources. HQ suggesst favoring a written agreement rather than operator logs or voice recordings.
- Even though HQ agrees that balancing authorities should use common metering equipment, we feel that R1 does not belong in BAL-005. This requirement relates to energy measurements that are used for accounting purposes and that do not come into play in reporting ACE calculation. This requirement should remain in BAL-006 and does not affect in any way automatic generation control. R8 does address perfectly the common metering needs between balancing authorities for real-time control.

Document Name:

Likes: 0

Dislikes: 0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer:

Answer Comment:

For BAL-005, R8, “MW Flow Values” should be specifically mentioned in R8 and not just in the R8 Rationale.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

General comment: Duke Energy recommends the drafting team consider moving the proposed R8 to R2. We feel that based on the common subject matter of both of these requirements, that it would be more appropriate to have them consecutively listed within a standard.

R4: Duke Energy requests further clarification regarding on how an entity may demonstrate compliance with R4.2 specifically. Also, more background information regarding where the 0.001Hz number came from and what it is measure against would add to clarity of the standard. Perhaps an Operating Guideline that provides guidance or examples on how an entity may demonstrate compliance, as well as a background on the 0.001Hz number.

R5: We request further clarification on the use of the term operator in R5. Is this in reference to a System Operator, if so, we recommend stating so in the standard. As written, it appears that the standard is in conflict with the rationale for R5 which uses the term System operator.

Document Name:

Likes:	0
Dislikes:	0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer:

Answer Comment:

As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer:

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer:

Answer Comment:

In the Automatic Generation Control (AGC) definition consider removing “Automatically adjusts” and replace it with “determines”. The BA does not always have the capability of making an automatic adjustment. For example, a BA can send a requested loading value down through the RIG (Remote Intelligent Gateway) and have the local GO/GOP or DP/LSE with smaller units to meet the load, but do not have direct control over the units. It’s the local GO/GOP or DP/LSE who owns and/or operates the units that actually execute changes in loading.

Requirement R1

The use of the following text needs to be reconsidered:

… each Tie□Line, Pseudo□Tie, and Dynamic Schedule with an Adjacent BA…

… time-synchronized common source…

… to determine hourly megawatt□hour values

Pseudo-ties and Dynamic Schedules are not tie lines; they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE.

The phrase “time-synchronized common source” requires explanation. If two BAs are using a common source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly.

Agree that Real-time metering of interties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing issue not a Real-time issue. R1 should be revised to clarify the intent.

Suggest that the Real-time installation of meters be left to BA Certification.

Requirement R2

What is meant by a 6 second sampling rate? Is that that the rate that a BA samples the data values it has at the moment, or does the 6 seconds represent a time delay between real-time and ACE calculations? This can be an issue for BAs that make use of multi-tier samples, where Owner X samples a group of resources every X-seconds, then sends that block of data to the BA who would sample all the blocks every Y-seconds.

Traditionally, sampling rates were associated with how well a continuous function can be recreated. A sampling rate that is slower that the fundamental oscillations in the continuous function will not be able to reproduce that original function (the issue of aliasing as experienced in watching a TV program in which a wheel appears to rotate in the wrong direction).

What is the reliability justification for this scan rate?

Requirement R4

The value of monitoring system frequency is recognized, but again as suggested in our response to R1, the issue of frequency monitoring would seem to be better suited to a certification process rather than to a mandatory standard.

What is the justification for the values in Parts 4.1 and 4.2?

Requirement R5

The value of alarming is recognized, but given the fact that R5 could be a federal law, the question could be asked:

- What constitutes “quality” as in quality flags?
- What constitutes “invalid” as in invalid data?

The concern addressed in R5 (alarming) would be better addressed in certification. The systems that are certified should have alarming processes built into them, customized to the needs of the BA.

Requirement R6

Real-time errors in the ACE components are reflected in various other parameters:

1. System Frequency

2. Time Error (even if TE is not a standard is still computed)

3. End of Day checkouts

4. End of Month billing

As written R6 is an exercise is data collection and manipulation.

What are the implications of an unavailability less than 99.5%, and at what points are reliability impacted (and how)?

Requirement R7

Requirement R7 requires clarification.

The process of monitoring for data errors and the process for mitigating errors that are identified are built into modern EMS systems.

The requirement as written focuses only on errors “affecting the scan□rate accuracy of data used in the calculation of Reporting ACE…”. As written, this is not all data used in ACE. Moreover, data does not impact the accuracy of the rate of scanning. The rate of scanning is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly.

As written R7 does not rise to the level of a NERC standard and should be deleted.

The intent of R1 should be to ensure that a common metering point be identified for all Real-time inter-BA tie lines. The issue of Pseudo-Ties and Dynamic Schedules is really a business agreement between the two BAs in cooperation with the resource being used, and therefore is not a standard matter.

Requirement R8

The requirement is on Pseudo-ties and Dynamic Schedules, but Pseudo-Ties and Dynamic Schedules are not tie lines, they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BA's ACE.

The requirement to utilize a common source for all interties is a valid requirement.

The agreements referred to in R8 are Interconnection Agreements and therefore not a matter for a NERC standard.

Document Name:

Likes: 0

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer:

Answer Comment:

See file attached to Question 1 for the SRC comments on the rationale and language of several requirements.

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

In general, BPA agrees with the current draft of BAL-005-1 but has some concerns with how BAs will meet the proposed R7 – relating to implementing an "Operating Process". BPA believes that R7 is poorly written and needs to be revisited.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter	Segment
Shawna Speer	1
Entity	**Region(s)**
Colorado Springs Utilities	

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

Identification of common sources of measurement (R8) and recording (R1) are BA certification items, not ongoing responsibilities that need to be checked periodically. New tie lines or "inputs" into the BA ACE calculations should be captured in FAC-001.

There is continued confusion regarding the six second scan rate. A BA can demonstrate a scan rate of its received data every six seconds, but there is no requirement for the data "made available to" the BA to be scanned at a certain scan rate. To be more clear, the requirement should specify that "measurements should be made by the common source(s) and provided to the BA at least every six seconds for the calculation of Reporting ACE". At its worst, that should result in an ACE calculation being made and reported with data no longer than 12 seconds old.

The Rational for Requirement R3 leads with a sentence that has no basis in the Functional Model and should be deleted. The RC does not have responsibility "for coordinating the reliability of bulk electric systems for member BA's." The RC is responsible for "Mitigating energy and transmission emergencies" among other things. The statement made in the Rationale overstates the responsibility of the RC and minimizes the BA role. The BA has primary responsibility for maintaining load and generation balance and the RC has authority to step in and provide assistance if the BA is unable to maintain its obligations. Delete the first sentence of the Rationale for R3 box. What purpose does it serve to allow a BA an additional 15 minutes after 30 minutes of an inability to calculate ACE before notifying the RC. Delete “within 45 minutes of the beginning … ACE” and replace with “without delay”. As stated, the requirement would allow a BA to not calculate Reporting ACE for 44 minutes and then notify the RC. Or would require a BA that could not calculate Reporting ACE for 31 minutes but then was successful to also notify the RC. The intent of the change is not clear and seems to indicate a reduction in reliability.

What is the specific rationale for requirement of 99.95% (or 0.05% outage allowance = 43 seconds/day) uptime for frequency measurement? Is some reliability threshold crossed at 44 seconds of frequency measurement unavailability each day? Is the intent of R4.2 to still require calibration of the measurement or simply to utilize a provided significant digit of .001 Hz? The new R4 uses the term “accuracy” of .001Hz rather than the old R17 description of “<=0.001Hz”. Also the measurement M4 requires demonstration of “minimum accuracy” which lends itself to requiring a demonstrable calibration that is not specifically stated in R4. The intended statement in the mapping document for R17 to R4 is not captured well in the resulting R4.

Suggest deleting R5 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data. If kept, the Measure M5 includes an additional requirement that the suspect/garbage data indication should be indicated on BOTH the calculated Reporting ACE result as well as on the individual suspect/garbage data point. We suggest that R5 should include similar language to M5 if that is the intent. The RSAW should be adjusted based on changes to R5 or M5.

Suggest deleting R6 as it is duplicative and in conflict with BAL-001-2. The reliability implication of “knowing” ACE is to be able to ensure balance is maintained. That is accomplished in CPS and BAAL and does not need to be duplicated here. The reporting % does not indicate a direct measurement of reliability and is administrative only.

Suggest deleting R7 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data.

Regarding R8: There is no demonstration of the reliability impact of using non-common meters between BA's for the purpose of Reporting ACE. In fact, in order to support reliability, the requirement should specify that redundant sources be made available to be used for Reporting ACE. Loss of the single, common source would result in lost input to the ACE calculation. A best practice that most BA's use is to identify a primary, common source for measurements and a secondary, common source for measurements and ensure each adjacent BA is using the same common source at the same time. *Common source measurements do not ensure accuracy, they just ensure the same error is introduced in both adjacent ACE calculations and therefore net each other out.*

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

5. Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

We do not see the need to retain any of the BAL-006 requirements in a NERC Reliability Standard. Standard. Inadvertent Interchange is calculated for reconciliation purpose and as such, does not have any reliability value for real-time operations or post-mortem analysis. The facilities used for recording hourly Inadvertent Interchange are more suited to be stipulated in the BA's Organization Certification Requirements; the procedure to calculate, reconcile and resolve disputes over Intervertent Interchange can be put into operating guide or even in the NAESB's business practices.

Consistent with the risk-based principle, we suggest that unless there is clear demonstration that failure to calculate and reconcile Inadvertent Interchange can adversely affect operating reliability, this standard should be retired with its requirements transferred to other NERC and/or NAESB documents.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:

R1 is embedded in R2 and R3 and therefore unnecessary.

The sub-bullets of R3 should be bullets and not Requirements. Additionally, the end-of-day check should be an agreement of on and off peak totals, not hourly values. There are INT standards that require confirmation of hourly schedules.

In the compliance section, RROs do not fill out monthly summary reports and submit them to NERC.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

The sub-requirements of R3 should be bullets, not sub requirements.

The end of day check should be an agreement of on and off peak totals, not hourly values. Confirmation of hourly schedules are already required in other standards.

Document Name:

Likes: 0

Dislikes: 0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer:

Answer Comment: No comments.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

We appreciate the SDT’s efforts to remove Requirement R3 from this standard.

Document Name:

Likes:	0
Dislikes:	0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

In the revised language for BAL-006-3 R4, Texas RE recommends replacing the undefined term "Regional Reliability Organization Survey Contact" with Reliability Coordinator. This may be outside the purview of the SDT but consideration should be provided to clarify the responsibility while the Standard is being considered.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Ameren supports MISO's comments for this question

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

n/a

Document Name:

Likes:	0
Dislikes:	0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer:

Answer Comment:

As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter
Colby Bellville

Segment
1,3,5,6

Entity
Duke Energy

Region(s)
FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer:

Answer Comment:

KCP&L incorporates by reference its response to Survey Question No. 2.

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer:

Answer Comment:

The SRC recommends that BAL-006 be retired.

See file attached to Question 1 for the full text of the comments to Question 5

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: None.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter
Shawna Speer

Segment
1

Entity
Colorado Springs Utilities

Region(s)

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

The purpose of BAL-006-2 (and resulting BAL-006-3) do not impact reliability. In fact, this enforceable Standard only serves to provide administrative metrics that are then used to facilitate either financial or in-kind reimbursements. In order to make this standard truly results based in relation to system reliability, requirements such as a BA shall not accumulate inadvertent interchange in excess of XX,XXX MWh per month would need to be created. No BA or RC will ever take reliability actions or issue Operating Instructions in relation to the accumulated or forecast accumulated inadvertent interchange. Resolution of inadvertent is an after-the fact reimbursement and not a reliability issue.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

6. Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

In the "Table of Compliance Elements", the Violation Severity Levels, R5 and R6 should correctly refer to Transmission Owner and Generator Owner, respectively (instead of Transmission Operator and Generator Operator)

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6

Entity	Region(s)
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name: Dominion submitted comments - 2010-14_2_1_BARC-Unofficial_Comment_Form-20150715.docx

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

APS agrees with moving these requirements from BAL-005 to the new FAC-001-3. APS also agrees with the proposed requirement language. APS does not agree that the measurements of these newly placed requirements have been correctly drafted.

A Transmission Operator, Generator Operator, or Load-Serving-Entity possessing the Facility interconnection requirements of the Transmission Owner they are attempting to interconnect with is not proof they are within a Balancing Authority Area. Evidence they are within a Balancing Authority Area would be demonstrated by possessing an executed Interconnection Agreement or similar contract. The measures will need to be corrected to reflect that. The RSAW will need to be corrected to line up with those changes.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

We concur with the proposed revisions to FAC-001-3.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:	
Document Name:	
Likes:	0
Dislikes:	0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Do not change FAC-001 as this confuses the intent of the original requirement. There is virtually no way to prove that a particular component is within a BA. The original requirement was intended to be sure Control Areas balanced. This is done by operating to common ties and performing Inadvertent Interchange checkouts.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Selected Answer:

Answer Comment:

1) FAC-001-3 R5 Severe VSL should state “The Transmission Owner……” to match R5 which places responsibility for the requirement on the Transmission Owner. Currently the VSL states the Transmission Operator will comply.

2) FAC-001-3 R6 Severe VSL should state “The Generator Owner……” to match R6 which places responsibility for the requirement on the Generator Owner. Currently the VSL states the Generation Operator will comply.

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

Should the SDT disagree that existing processes are adequate to accomplish the desired outcome (as described in the comments to Question #2), then the following is recommended:

1. Remove the inseration of 4.1.3 and R5-R7.
2. Modify R3.2 to read "Procedures for notifying the BA, TOP and RC of new or materially modified existing interconnections."
3. Modify R4.2 to read "Procedures for notifying the BA, TOP and RC of new interconnections."

Additionally, if possible, it is recommended that there be continued coordination with the FAC-001 team that produced FAC-001-2 in 2014 before any changes to FAC-001-2 are made.

Document Name:

Likes: 0

Dislikes: 0

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer:

Answer Comment:

As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Voter Information

Voter
Brian Van Gheem

Segment
6

Entity
ACES Power Marketing

Region(s)
NA - Not Applicable

Selected Answer:

Answer Comment:

We believe FAC-001-3 should not be modified based on the reasons previously provided in question #2. We recommend the SDT retire the requirements moved from BAL-005-0.2b based on the reasons cited. At a minimum, we recommend the SDT provide technical justification on why these requirements are necessary.

Document Name:	
Likes:	0
Dislikes:	0

Jonathan Appelbaum - United Illuminating Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

In R5, R6, and R7 it seems duplicitous to include, “metered boundaries” in the phrase “Balancing Authority Area’s metered boundaries” because the first sentence of Balancing Authority Area definition is “The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.”

Texas RE noticed the Evidence Retention section does not address LSEs.

Texas RE noticed the format of FAC-001-3 does not follow the new NERC Results Based Standards
Template.

Texas RE noticed the VSL for R5 refers to the “Transmission Operator” but the Requirement is applicable to the Transmission Owner. The VSL for R6 refers to the “Generator Operator” but the Requirement is applicable to the Generation Owner.

Document Name:

Likes: 0

Dislikes: 0

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer:

Answer Comment: Please see comment under Qustion 2 above.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

In our opinion there appears to be an inconsistency between the Standard and the Table of Compliance. The Applicability section 4.1.1 identifies the Transmission Owner as a Functional entity. Requirement R5 identifies the Transmission Owner with responsibility for confirming facilities are located within the BA boundaries. However, in the Table of Compliance Elements for requirement R5, the Transmission Operator is identified with this responsibility under the Severe VSL column. We believe that the Transmission Operator should be changed to Transmission Owner to be consistent with the requirements of the Standard.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

see question2

Document Name:

Likes:	0
Dislikes:	0

Scott McGough - Georgia System Operations Corporation - 3 -

Selected Answer:

Answer Comment:

1. R7 seems to not even fit with the stated purpose of FAC-001-3 for interconnecting (lowercase) to Facilities. What is the purpose of R7? Capitalized term “Interconnection” simply means “When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.” Reading the requirement at face value…if your load is anywhere in Eastern, Western , or ERCOT Interconnection area then confirm its in a BA Area’s metered boundaries. Is the intent of R7 to identify **which** BA area the load is in? or is the intent to simply identify “yes” it is in “a BAs Area’s metered boundary”? How does knowing or not knowing this have adverse impacts on the reliability of the BES with respect to the purpose of the standard?

In addition, note that from NERC’s filing to FERC – *Supplemental Information to Petition for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards*, RM15-16, dated May 12, 2015 – NERC states that “An LSE does not own or operate Bulk Electric System facilities or equipment or the facilities or equipment used to serve end-use customers.21 (footnote 21 - The Distribution Provider is the functional entity that provides facilities that interconnect an end-use customer load and the electric system for the transfer of electrical energy to the end-use customer. If a company registered as an LSE also owned facilities, the company would be registered for other functions as well.

2. Measure M7 implies that LSEs have Facility interconnection requirements when there are no such requirements, thus complicating complying with R7. Does the drafting team intend for the LSE to provide a copy of the Facility interconnection requirements documents they may have received from the TO when requesting to interconnect to the transmission owner?

3. Depending on understanding the true intent of this requirement, we would be in favor for an attestation to be included in the measure, but then … seems like a pointless, administrative requirement that meets P81.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter
Colby Bellville

Segment
1,3,5,6

Entity
Duke Energy

Region(s)
FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Information

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
LG&E and KU Energy, LLC	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer:

Answer Comment:

KCP&L incorporates by reference its response to Survey Question No. 2.

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Voter Information

Voter	**Segment**
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, suggest revising Requirement R7 to read "Each **Distribution Provider** that provides facilities that interconnect a customer Load shall confirm that each customer Load is within a Balancing Authority Area's metered boundaries." Measure M7 would need to be revised accordingly.

This standard is unnecessary given the fact that Interconnection Agreements are contractual legal documents that address and spell out the details addressed by the various FAC-001 requirements.

Also, the use of the requirement "shall address" is not a clear mandate and is open to interpretation by both the Responsible Entity and the Regional Enforcement entity.

The wording in Measures M5 thru M7 appear to have been copied from Measures M3 and M4, mentioning "dated, documented Facility interconnection requirements addressing the procedures" as evidence that the requirements are met. The wording in these Measures is appropriate for M3 and M4, but not M5 thru M7.

Document Name:

Likes: 0

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer:

Answer Comment:

In addition to the comments GTC listed in Question 2, GTC believes the response to R5 as a TO would simply be "yes" and is unaware how this answer enhances reliable operation of the BES. Therefore, GTC does not quite understand the intent of these requirements as they are written. Confirm which BA Area the Transmission Facility is located in? Confirm to whom? GTC see's this as administrative in nature subject to P81 criteria.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Hydro One supports all comments provided by NPCC RSC regarding the draft of FAC-001-3.

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Voter Information

Voter	Segment
Albert DiCaprio	2
Entity	**Region(s)**
PJM Interconnection, L.L.C.	RFC

Selected Answer:

Answer Comment:

The SRC recommends that FAC-001-2 be retired

See file attached to Question 1 for the full text of the comments to Question 6

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: None.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Group Information

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Voter Information

Voter

Shawna Speer

Segment

1

Entity

Colorado Springs Utilities

Region(s)

Selected Answer:

Answer Comment:

Again to illustrate the comments in response #2, FAC-001 is a facility interconnection requirement standard so any changes here will be applied to FAC-001 applicable functional entities documented facility interconnection requirements. FAC-001 typically deals with **new interconnections**, so if the intent of the FAC-001-3 R5-R7 is to make sure all transmission, generation, and load are within a BAA metered bounds this is not the correct standard. R7 in its entirety needs to be moved to another standard since it is not clear which interconnection requirement it will fall under (i.e. TO and/or Applicable GO).

The FAC-001 standard can be used to require documented facility interconnection requirements to address BAA metered bounds for all entities **seeking to interconnect**. However to enforce this for BAA metered bounds for those facilities that already exist within FAC-001, the documented facility interconnection requirements would have to retroactively apply for those facilities that already exist. R5-R6 needs to be moved to another standard.

Document Name:

Likes:	0
Dislikes:	0

Jason Smith - 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	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Voter Information

Voter	Segment
Jason Smith	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

The first 4 requirements, which make up the existing FAC-001-2, are administrative and should be moved to certification review. The new R5-7 are necessary due to the removal from BAL-005. However as suggested earlier, those requiremetns should also be included in the TO’s Facility Interconnection Requirement documents and do not necessarily need to be specific Reliability Standard Requirements. If R1-4 are kept, we recommend changing the phrase “shall address” in R1-4 to “shall include”.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation agrees with the periodic review team that it is important to verify facilities are within the metered boundaries of a Balancing Authority Area before they are operational, but believes that the requirement should be imposed through interconnection or service agreements rather than a reliability standard. As an alternative, FAC-001-3 R5 through R7 and M5 through M7 could be rephrased to require a one-time confirmation prior to a facility being placed in service.

Document Name:

Likes: 0

Dislikes: 0

Unofficial Comment Form

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls

Do not use this form for submitting comments. Use the electronic form to submit comments on the proposed revisions to **BAL-005-1 – Balancing Authority Control, BAL-006-3 – Inadvertent Interchange, FAC-001-3 – Facility Interconnection Requirements**. The electronic form must be submitted **by 8 p.m. Eastern, Monday, September 14, 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

This posting is soliciting formal comments on the draft standards BAL-005-1 Balancing Authority Control, BAL-006-3 Inadvertent Interchange and FAC-001-3 Facility Interconnection Requirements.

On September 19, 2013, the NERC Standards Committee appointed ten subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT).[1] As part of its review, the BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0.2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. The recommendations of the BARC 2 PRT are in the Periodic Review Templates and SAR.

The Standards Committee approved a revised SAR to be posted for a 30-day comment period on June 10, 2014. The SAR was posted for comment from July 16, 2014 through August 14, 2014. The BARC Phase 2.1 standard drafting team (BARC 2.1 SDT) reviewed the comments received from the SAR posting and has developed revisions to BAL-005-0.2b, BAL-006-2 and FAC-001-2 standards. The BARC 2.1 SDT has completely re-written the BAL-005 standard, moved one requirement from the current BAL-005 standard into the proposed FAC-001-3 standard and moved one requirement from the current BAL-006 standard into the proposed BAL-005-1 standard. The balance of the requirements in the BAL-006-3 standard will be reviewed for revision and posted at a later date.

This project addresses directives from FERC Order 693, and provides additional clarity to many requirements, as well as retiring requirements that meet the criteria developed in the Paragraph 81 project.
This posting is soliciting comment on three standards; 1) BAL-005-1 Balancing Authority Control; 2) BAL-006-3 Inadvertent Interchange; and 3) FAC-001-3 Facility Interconnection Re1quirements.

[1] The Standards Committee subsequently appointed an eleventh SME to the BARC 2 PRT.

Questions

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:
   ~~**NOTE** - Dominion has no entity registered as BA and will not submit any comment on this question.~~

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

   ☒ Yes
   ☐ No

   Comments:

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:
   ~~**NOTE** - Dominion has no entity registered as BA and will not submit any comment on this question.~~

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

   Comments:

5. Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.

   Comments:

6. Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.

   Comments:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, Dominion suggests revising Requirement 7 to read "Each ~~Load-Serving Entity~~ **Distribution Provider** ~~with Load operating in an Interconnection~~ that provides facilities that interconnect an e~~E~~nd-use c~~C~~ustomer load shall confirm that each e~~E~~nd-use c~~C~~ustomer Load is within a Balancing Authority Area's metered boundaries. If this suggestion is accepted by the SDT, corresponding changes would need to be made to Measure 7.

1. **The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.**

☐ Yes
☒ No

Comments: It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

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

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

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

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

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

4. **Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.**

Comments:
The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time synchronized". AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall ~~ensure that~~ have a process to operate to common, accurate ~~each~~ Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its ~~an~~ Adjacent Balancing Authorities. ~~is equipped with a mutually agreed upon time synchronized common source to determine hourly megawatt-hour values~~

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Unofficial Comment Form

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls

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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.

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This project addresses directives from FERC Order 693, and provides additional clarity to many requirements, as well as retiring requirements that meet the criteria developed in the Paragraph 81 project.
This posting is soliciting comment on three standards; 1) BAL-005-1 Balancing Authority Control; 2) BAL-006-3 Inadvertent Interchange; and 3) FAC-001-3 Facility Interconnection Re1quirements.

[1] The Standards Committee subsequently appointed an eleventh SME to the BARC 2 PRT.

Questions

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

Rationale:

1. The BAL-005 definitions should not include any references to Automatic Time Error Correction (I ATEC).

   BAL-005 is a NERC standard applicable to all Interconnections - not one of the many regionally-approved standards. This standard is approved for all BAs unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. As such, the SRC believes the definition and references to Automatic Time Error Correction (I_{ATEC}) should be deleted and left to the regionally-approved regional standard.

2. The following phrases / terms used in the proposed definition of AGC are ambiguous or not precise.

   - Centrally located equipment

     This phrase should be deleted.

     There is no justification to link the definition of Automatic Generation Control (AGC) to a given location given that AGC is a process (software) not equipment (hardware).

- …that automatically adjusts…

  This phrase should be reworded.

  There is no direct link between an AGC signal and the response of a resource. As written the failure of a resource to respond to an AGC signal would constitute a violation on the part of the BA.

  It would be more correct to state that AGC "is <u>used to adjust</u> resources".

- …maintain Reporting ACE…

  This phrase should be deleted.

  AGC is not designed for reporting purposes. AGC is designed to assist in the control of a BA's balancing of its resources to its NERC mandated balancing obligations.

- Resources utilized under AGC…

  This sentence should be deleted.

  - AGC does not "utilize" resources, but – rather – evaluates resource utilization within a balancing Authority Area to ensure that load and resources remain in balance. More specifically, resources are an input to AGC.
  - The sentence itself is a partial list of supply resources and therefore not critical to defining the term itself.

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

   ☐ Yes
   ☒ No

   Comments:

   The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

Rationale: (also see response to Question 6 below)

1. BAL-005-0.2b R1 addresses AGC. R1.1 – R1.3 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
2. If R1 and its sub-requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

Rationale:
The SRC opposes this proposal for the following reasons:

1. The two standards address issues that are in two different time horizons (BAL-005 is a real time horizon (MW), while BAL-006 is an hourly horizon (MWhr). To combine the two standards into a single standard will confuse the objectives of each of these time horizons and the associated functions.
2. The collection of hourly (Inadvertent Interchange) data proposed by the transferred requirement (R3) does not affect the real time calculation of Reporting ACE. BAL-006 is a standard for Inadvertent Interchange which is an after-the-fact accounting function as opposed to BAL-005 which is about real-time reliability function.
3. Real time metering of interconnecting points is better handled as a certification issue given that such metering is relatively static and stable and does not require continuous the continuous review mandated by a reliability standard.
4. The objective of R3 is not clear as currently proposed. Specifically, it is unclear if R3 is meant:
   - As a procedural mandate that BAs use a single real-time point of metering for interconnection points used in the ACE calculation?
   - As a data reporting mandate on meters, that all interconnection point meters have the ability to compute hourly readings? or
   - As a data reporting mandate on BAs to communicate information on interconnection points once an hour to adjacent BAs (in which case there is a need for a time criteria – e.g. send the information within 4 hours of the clock hour).

Additionally, if Requirement R1 is meant as a data reporting requirement, it should have been considered for retirement under the Paragraph 81 concept. If not, additional clarification is needed, *e.g.*, is it a certification requirement that mandates hardware.

The SRC also notes that NERC's Independent Expert Review Panel recommended BAL-006 for retirement because "This is only for energy accounting. Covered by Tagging requirements."

4. Please provide any issues you have on this draft of the **BAL-005-1** standard and a proposed solution.

   Comments:
   The SRC provides comments on the rationale and language of several requirements below by requirement.

Requirement R1

The SRC recommends:

- The rationale for R1 be reconsidered and corrected.
- The references in R1 to "time-synchronized common source" and "hourly megawatt-hour values " be deleted.

Rationale

The SRC questions the following text in the proposed "*Rationale for Requirement R1*":

- The intent of R1 is to provide accuracy…
- R1 …used in… Reporting ACE, hourly inadvertent energy, and Frequency Response measurements
- It [R1] specifies need for …instantaneous and hourly integrated …tie line flow values
- Common data source requirements also apply …

The intent of R1 is not accuracy (common source metering does not address accuracy). The intent of R1 is to ensure a zero-sum data ensemble for all ACEs.

Contract-based billing meters used for Inadvertent Interchange are not necessarily the same as the real time common source meters used in ACE. The text of R1 is not precise in what is the specific objective for R1. The rationale states R1 is for instantaneous and hourly tie flow values but the text of R1 states it is "…to determine hourly megawatt-hour values."

The final sentence in the Rationale section regarding of other R1 applications is superfluous and should be deleted.

The SRC questions the following text:

- … time-synchronized common source…
- … to determine hourly megawatt-hour values

The phrase "time-synchronized common source" requires explanation.

If two BAs are using a common (MW) source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values (MWh) the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly.

The SRC agrees that real time (MW) metering of inter-ties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing issue not a real time issue. In short, the SDT is asked to rewrite R1 in a fashion that clarifies the intent.

Requirement R2

The SRC recommends:

- The rationale for R2 be reconsidered and revised.

Rationale

The proposed "*Rationale for Requirement R2*" overstates its justification. Specifically the rationale states that without frequency "…the BA operator will lack situational awareness and will be **unable** to make correct decisions when maintaining reliability."

The SRC does not agree that a BA would be "unable" to make correct decisions. The SRC acknowledges that decision-making regarding impacts on and the support for frequency may be more difficult. However, this difficulty does not threaten the reliability of the interconnection as tie line flows will still be monitored by TOPs and system frequency will be monitored by other BAs, TOPs and RCs.

Requirement R4

The SRC recommends that sub-requirements (4.1 and 4.2) be deleted.

Rationale:

The SRC recognizes the value of monitoring system frequency, but suggests that the monitoring of the availability and accuracy of frequency-monitoring equipment is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements would be better suited to be addressed as part of a certification process or in guidance documents than as a mandatory reliability standard.

In lieu of deleting the sub-requirements, the SRC requests the justification for the values in R4.1 and 4.2, and for the benefits to reliability that is to be obtained through the proposed requirements.

Requirement R5

The SRC recommends:

- R5 be addressed as part of a certification process.
- The rationale for R5 be reconsidered and revised.

Rationale

The SRC believes R5 (alarming) would be better addressed in certification than as part of a reliability standard that is subject to continuous review as a reliability standard requirement. The systems that are certified should have alarming processes built into them that are customized to the needs of the respective BA. Such systems, once reviewed, are relatively static and not subject to frequent modification. Additionally, although the SRC recognizes the values of alarming, it is concerned that, in the context of a mandatory reliability standard, subjectivity will be introduced regarding what constitutes "quality" for quality flags, and "invalid" for invalid data. Without an objective measure for the aforementioned terms, Requirement R5 loses any value as a reliability standard.

The proposed "*Rationale for Requirement R5*" states "When an operator questions the validity of data, actions **are delayed** and the probability of **adverse events** occurring **can increase**." While the above could be true, there is no objective evidence to support the statement and therefore the statement should be deleted.

Requirement R6

The SRC recommends requirement R6 be deleted.

Rationale

The SRC recognizes the value of monitoring ACE calculation, but suggests the monitoring of the availability of the software, etc. utilized to calculate ACE is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements are better addressed during the certification process and in guidance documentation than as part of a mandatory reliability standard.

The SRC is concerned that certain terms such as "available system" create ambiguity, e.g., what would constitute an "available system." Neither the requirement nor the measurement makes clear what an available system is nor when a system would be deemed unavailable, e.g., is a system "unavailable" to compute ACE if a single data sample is unavailable? Or when the entire system is unavailable.

Requirement R7

The SRC recommends:

- R7 be deleted.
- The rationale for R7 be reconsidered and revised.

Rationale

The SRC suggests that as written, R7 is an administrative requirement that does not rise to the level of a NERC standard and should be deleted.

Should Requirement R7 be retained, the SRC comments that the objective and obligation of a BA under requirement R7 is ambiguous and requires additional explanation/clarification. Additionally, the process of monitoring for and mitigating data errors that are identified are built into modern EMS systems. Thus, the SDT proposed requirement for an "Operating Process," which is not a defined term in Glossary and should not be considered a proper noun in this requirement, would be redundant of existing processes and functionality. Further, the requirement focuses only on errors "affecting the scan-rate accuracy of data used in the calculation of Reporting ACE…" The SRC asserts that data (in and of itself) generally does not impact the accuracy of the rate of scanning, which is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly.

The *Rationale for R7* states that "…Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system."

The SRC requests that either justification and support for this statement be provided, or the statement be deleted from the rationale section.

Requirement R8

The SRC recommends:

- R8 be reviewed and revised.
- The *Rationale for R8* be reconsidered and revised.

Rationale

The SRC believes that the issue of common source metering for all inter-ties, and of agreements on allocating resources as pseudo-ties or dynamic schedules is best handled as Interconnection Agreements or certification rather than as a reliability standard.

The SRC notes that Requirement 8 includes Pseudo-ties and Dynamic Schedules but Pseudo-ties and Dynamic Schedules are not tie lines, but are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE, and thus do not derive from common source meters.

The *Rationale for R8* states that "…When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action." The SRC objects to this statement.

If data sources are not common, then the ACE values in an Interconnection no longer form a zero-sum system. Such an error can only be identified in a tie-line by tie-line check. The result can be all BAs meet the Control Performance requirements, but the Interconnection itself is experiencing an imbalance that results in off-schedule frequency and time error. The SRC would point out that any inaccuracies or errors in the ACE components are reflected in various other parameters:

- System Frequency
- Time Error
- End of Day checkouts
- End of Month billing

Thus, no confusion would result and this should be deleted form the rationale
The *Rationale for Requirement R8* also states "The intent of Requirement R8 is to provide accuracy in the measurement and calculations." Common source metering does not provide accuracy as the data can still be in error. What common source metering does provide is a zero-sum system. Thus, the SRC requests that the rationale be modified to more accurately reflect the impact of data sources on accuracy.

5. Please provide any issues you have on the proposed change to the **BAL-006-3** standard and a proposed solution.

   Comments:
   The SRC recommends that BAL-006 be retired.

   Rationale:
   Inadvertent Interchange is an accounting metric not reliability metric.

   The BAL-006 requirements are administrative mandates related to after-the-fact accounting should be retired under Paragraph 81.

   Any value of Inadvertent Interchange is as an internal control process and would best be memorialized in a form other than a standard.

6. Please provide any issues you have on the proposed change to the **FAC-001-3** standard and a proposed solution.

   Comments:
   The SRC recommends that FAC-001-2 be retired (also see response to Question 2 above)

   Rationale:
   1. Requirements R1 – R4 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
   2. Requirements R5-R7 are certification issues. If these requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

NERC

Consideration of Comments

Project Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-3 & FAC-001-3

Comment Period Start Date: 7/30/2015

Comment Period End Date: 9/14/2015

Associated Ballot: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 IN 1 ST

There were 46 sets of responses, including comments from approximately 131 different people from approximately 87 different companies representing 9 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. **The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.**
2. **The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.**

3. **The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.**
4. **Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.**
5. **Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.**
6. **Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.**

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. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Andrew Pusztai - American Transmission Company, LLC - 1 -	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Selected Answer:	Yes
Richard Vine - California ISO - 2 -	
Answer Comment:	The California ISO supports the comments of the ISO/RTO Council Standards Review Committee for all questions in this Survey.
Response:	

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

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
Shannon Weaver	Midwest ISO Inc.	MRO	2

Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Selected Answer: Yes

Answer Comment: **We agree it makes AGC more inclusive and understand there was a FERC directive to make this change, but the directive does not add to reliability.**

Thank you for your affirmative response and clarifying comment. The SDT has further modified the definition of AGC.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Likes: 0

Dislikes: 1 DTE Energy - Detroit Edison Company, 5, DePriest Jeffrey

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: Yes

Answer Comment: We agree that the modified definition is a step in the right direction. However, the definition references Demand Response in capital letters. While that concept is recognized by industry, it officially is not a NERC Glossary Term. We recommend that SDT rephrase the last sentence of this definition to read “Resources utilized under AGC may include, but not be limited to, conventional generation, variable energy resources, energy storage devices, and demand response resources.”

Response:	Thank you for your comments. The SDT has made changes to the definition of AGC to help resolve this issue.
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	No
Answer Comment:	Texas RE does agree that the revised definition is more inclusive. There is a concern, however, about disregarding asynchronous Tie MWs in the calculation for Reporting ACE. If a Balancing Authority (BA) has 1000 MWs of generation and 500 MWS of load with the remaining generation being transferred asynchronously, how will the ACE equation , and subsequently AGC, work properly? The Reporting ACE equation accounts for all generation and load. Any asynchronous Tie MWs to another Interconnection is accounted as either load or generation including such transfers. With the revised definition of Reporting ACE, it appears the Standard Drafting Team (SDT) is disregarding single BA Interconnections, such as ERCOT and Quebec. Texas RE is concerned about the statement “All NERC Interconnections with multiple Balancing Authority Areas operate using the principles of Tie-bias (TLB) Control and requirement the use of

an ACE equation similar to the Reporting ACE defined above." This statement implies that single BA Interconnections, such as ERCOT and Quebec do not operate using the principles of TLB and the use of ACE. If not, how does BAL-001 apply? Is indicating an "alternative" method for a Reporting ACE equation use advocating regional differences?

The SDT believes the Reporting ACE still is applicable to a single BA interconnection using the principles of Tie-bias control. However, the SDT has made the following modification:

All NERC Interconnections 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.

Texas RE inquires as to whether it is the SDT's intent that AGC (as currently defined in the proposed definition) will be only frequency-based for single-balancing authority areas.

The definition does not change how one uses AGC nor does it change the applicable NERC Reliability Standards. In addition the SDT has modified the definition to add clarity. Please refer to our responses to Question #4 for additional information.

Response:

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3

Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA supports using the term resources to make the definition more inclusive, but the capitalized term Demand Response is not in the NERC glossary of terms.

The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment: PJM finds that the modified definition of AGC is inclusive of more resource types than only traditional generation resources. However, AGC equipment does not directly adjust the output of resources, but instead generates and sends control signals to the resources to change output. PJM suggests the following change to the definition for clarity:

Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjusts resources in a Balancing Authority Area to help maintain the Reporting ACE in that

	of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. Resources utilized under AGC may include, but are not limited to, conventional generation, variable energy resources, storage devices and loads acting as resources (such as Demand Response). The SDT has made changes to the definition of AGC to help resolve this issue.
Response:	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:	Yes
Answer Comment:	AGC is no longer used in BAL-005-1, therefore HQ questions whether Project 2010-14.2.1 is the best opportunity to revise this definition. The SDT has made changes to the definition of AGC to help resolve this issue. However, since AGC adjustment impacts Reporting ACE, and Reporting ACE is critical for BAL-005, the SDT felt it was appropriate to adjust the definition under this process.

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Answer Comment: The modification is on the correct track to expand the definition.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy recommends that the drafting team clarify or state that just because a term appears in a definition does not make the**

definition applicable to said term. For example, the term *"Demand Response"* appears in the proposed definition of Automatic Generation Control (AGC), however, AGC does not adjust Demand Response. Clarification is needed from the drafting team stating that just because this term appears in the definition, this doesn't mean every type of Generating Resource, Load Resource, or Load reacting as a resource is capable of providing response to an AGC signal. Just because a term is listed in the definition, doesn't mean it should qualify as an example. We suggest the drafting team revise the language to include *"such as qualified demand resources"* rather than *"Demand Response"* which can mean a lot of different things.

The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Selected Answer: No

Answer Comment:

These comments are submitted on behalf LG&E and KU Energy, LLC (LG&E/KU). LG&E/KU is registered in the SERC Region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, RP, TO, TOP, TP, and TSP

Comments:

Making a definition “more inclusive” does not make it clearer or better. In fact, an argument can be made that an “inclusive” definition can become problematic. The proposed definition includes uneccessary, prescriptive language on what types of resources may be used for AGC. We are concerned that the list will raise expectations that VERs, storage devices and Demand Response resources should be included in an entity’s AGC function. Many Demand Response programs (such as residential load interruption) are not compatible with AGC operations and should not be considered as such.

The last sentence of the proposed definition is not necessary, reduces the clarity of the definition and should be deleted.

	Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjust resources in a Balancing Authority Area to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. The SDT has made changes to the definition of AGC to help resolve this issue.
Response:	

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer:	Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:	Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5

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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment:

The use of centrally located equipment, that automatically adjusts, maintain Reporting ACE, resources utilized under AGC needs to be considered.

There is no justification to link the definition of Automatic Generation Control (AGC) to a given location.

AGC is not hardware (equipment); AGC is software.

AGC does not “adjust resources” (that is usually accomplished at the resource itself). AGC “is used to adjust resources”.

AGC is not designed for reporting purposes. AGC is design to assist in the control of a BA’s balance of its resources to its NERC mandated balancing obligations.

Propose that the definition be revised to:

Automatic Generation Control (AGC): Software designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.

The SDT has made changes to the definition of AGC to help resolve this issue.

BAL-005 being a NERC standard and not one of the many regionally-approved standards is applicable to all Bas unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. Automatic Time Error Correction is not a part of the FERC-approved standards for all Bas. For clarity the regionally-approved definition and references to **Automatic Time Error Correction (I ATEC)** be deleted and left to an approved regional standard.

Under the FERC Order approving BAL-001-2 (Real Power Balancing Control Performance) NERC was directed to include ATEC in the ACE equation. Since Reporting ACE includes the definition for the Western Interconnection, ATEC must be defined and included in the definitions. The Reporting ACE definition was broken into sub-definitions to easily manage the specific Reporting ACE equation for each Interconnection, such as the ATEC term for the Western Interconnection.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment: The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

The SDT has made changes to the definition of AGC to help resolve this issue.

See attached for the full text of the comments to Questions 1-6

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3

Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: No

Answer Comment: The added sentence at the end of the definition adequately serves the purpose of clarifying that all “resources” are included rather than just traditional generators. The change to add the descriptor “Centrally located” when describing the “equipment” is also problematic. There does not appear to be a stated justification for making that change and it could introduce issues in interpretation surrounding redundant systems or sub-systems that could or should be included in the system that is used for AGC. If there is a reason for continuing to include the “centrally located” descriptor, we suggest that the SDT clarify the reason.

	The SDT has made changes to the definition of AGC to help resolve this issue.
Response:	
Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	Yes

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

General Response of the SDT to comments received:

Has there ever been a situation where Load was not within a BA metered boundary? The answer to this question is yes, but it is the wrong question. The correct question is, "Can the addition of a new load without notice to the BA affect the ability of a BA to perform its balancing function adequately and thus detrimentally affect reliability?"

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Andrew Pusztai - American Transmission Company, LLC - 1 -	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Selected Answer:	Yes
Thomas Foltz - AEP - 5 -	
Selected Answer:	No
Answer Comment:	We do not agree that FAC-001 is the correct standard to house these obligations. FAC-001 applies to the interconnection of new facilities, while the R5, R6 & R7 Requirements taken from BAL-005-0.2b apply to all Transmission, Generation & Load facilities.

Response to Comment:	The SDT proposed changes to FAC-001, as it does not solely apply to the interconnection of new facilities, but it also requires notification of "new or materially modified existing interconnections". Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability

	issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. In the event that the drafting team *is* successful in moving these obligations to FAC-001, the new requirements will need to be clarified so that the requirements apply only to new interconnecting facilities (consistent with the spirit of the other FAC-001 requirements). In that case, separate requirements will still be required elsewhere to apply to existing Transmission, Generation & Load facilities. In addition, it would also be incumbent on the TO to ensure that the wording for these obligations are explicit within their interconnect agreements and the necessary interconnect guides that are specified in FAC-001. The SDT agrees that the requirements should be re-worded and has made the necessary modifications. AEP's decision to vote negative on this proposal is driven by these objections.
Answer Comment:	

Response to Comment:

Response:

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Selected Answer:	Yes
Jeremy Voll - Basin Electric Power Cooperative - 3 -	
Selected Answer:	No
Answer Comment:	It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows. R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area. The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with

	other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Answer Comment:	M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Response:

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Selected Answer: No

Answer Comment: See attachment with strikethrough.

It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

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

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

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

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

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is

	within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3, and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability

	issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.
Answer Comment:	**M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.**
Response:	

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:	No
Answer Comment:	It is not necessary to move this requirement. The requirement can be improved by keeping it where it is and limiting it to: R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area. The requirement is a concept from the NERC Operating Manual (Control Area Criteria) that was swept into the V0 standard. There is only one way to prove that everything is within the metered bounds of a BA, that is through

	Inadvertent Interchange accounting. Thus the measure for this requirement should be:
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that

	they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Answer Comment:	M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.
Response:	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No
Answer Comment:	BAL-005-0.2b R1 should remain where it is, but would be improved by the removal of the sub Requirements. The only means to prove that everything is within the metered boudaries of a Balancing Authority is through Inadvertent Interchange accounting. The revised R1 should read: R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

	the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The measure M1 should read: M1. The Balancing Authority was unable to

Answer Comment: agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstate its Nets Actual Interchange value in its Inadvertent Interchange accounting.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: While there is agreement with the removal of R1 from BAL-005-0.2b, the insertion of 4.1.3, and R5-R7 into FAC-001-2 is not required. Notification of an entities inclusion within a Balancing Authority's metered boundaries can be accomplished through the NERC Rules of Procedure, Section 500, FAC-001-2, proposed standard TOP-003-3 and existing standard IRO-010-2. For example, sufficient latitude exists within FAC-001-2 as approved, for the TO to provide notification to "those responsible for the reliability of the affected

	system(s) of new or materially modified existing interconnections." Through this requirement, the TO can provide a list of new or modified facilities (such as new or modified load, transmission and generator connections) to the TOP, BA and RC.
Response to Comment:	In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE

	addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Response:	

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC	
Selected Answer:	No
Answer Comment:	As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: No

Answer Comment: 1. We concur that the intent of BAL-005-0.2b Requirement R1 provides for identification of Interconnection Facilities and not for the calculation of

	Reporting ACE. We question if the SDT followed the recommendations of the Project 2010-14.2 BAL Standards PRT to "explore if the role of the TOP would appropriately cover the loads interconnected to that TOP such that the LSE requirement may not be necessary." We ask the SDT to provide rationale for the proposed FAC-001-3 standard to explain their conclusion on why they continue to list the LSE as an applicable entity. We remind the SDT that the retirement of the LSE is pending FERC approval through the Risk-Based Registration (RBR) initiative. We do not understand why the SDT feels like the LSE has a reliability role, when the ERO continues to argue that the LSE is primarily focused on commercial activities and other entities, such as the TOP, would continue to meet reliability needs without the LSE. We strongly recommend that the drafting team remove the LSE from the applicability section. 2. As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring." If a BA needs information regarding a particular load, generation resource, or transmission line operating within its BA Area, based on this requirement, would they not "identify" the correct entity to send their specification? Furthermore, NERC has spent significant time and resources on the development of the BES definition and the removal of the LSE from its functional model. These efforts were accomplished to focus on entities and facilities that posed a significant risk to BES reliability. The SDT has already identified that the intent of these requirements is not for the

	calculation of Reporting ACE and only the identification of entities. Moreover, if a generation resource, transmission line, or load is not properly accounted for in the calculation of Reporting ACE, Inadvertent Interchange will result and the BA would investigate to correct the discrepancy, as a best practice, accordingly. We recommend the SDT remove these requirements from the proposed draft standards.
Response to Comment:	In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following

	words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	
Jonathan Appelbaum - United Illuminating Co. - 1 -	
Selected Answer:	No
Answer Comment:	First, a quick review of the Standards shows there is no other specific requirement to ensure a facility is in a metered boundry or telemtery is provided to a RC, BA, or TOP. This requirement is to ensure that a load or generator is metered and communicated to BA for BA function. It is just as important that line metering is reported to TOP and RC, yet there is no FAC requirement to install metering and telemetry. For TOP and RC, there is TOP-03 and IRO-010 with a data specification and process to deliver data.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the

	Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.
Answer Comment:	Second, FAC-001 is about developing a single document for one-time use by an interconnecting entity to know what is required to complete an interconnection. The proposed change creates an ongoing requirement to conform that the interconnection is in the metered boundaries of the BA. The proposed requirement is not consistent with FAC-001. A consistent approach to FAC-001 is to require that the requirements address the metering required to facilitate the BA function, but this is already implied in the current FAC-001-2 standard.
Response to Comment:	The SDT has modified FAC-001 to address your issue.
Answer Comment:	Balancing is becoming a complicated function as compared to the Version 0 days. The BA should have its own data specification standard similar to TOP-003 or IRO-010. In the alternative these requirements should be retired, with the comment that the requirement is implied already in FAc-001-2 and

	the Technical and Guideline section of FAC-001-2 will be updated to include a specific explanation of including interconnection in BA metered boundary. The goal of the NERC Reliability Standards are to be clear not to imply requirements.
Response to Comment:	
Response:	
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	
Selected Answer:	No
Answer Comment:	Texas RE noticed that the Load-Serving Entity (LSE) function was added to the FAC-001-3 applicability but is not mentioned in the Evidence Retention section. Thank you for your comment. The SDT has made the necessary modifications. The LSE has been removed from the standard based on the RBR initiative. Texas RE noticed the term, “Transmission Facilities” is capitalized in R5 but not in R1.2. The term “Transmission Facilities” is not a defined term in the NERC glossary so it could cause confusion if capitalized. Thank you for your comments, the SDT has incorporated your suggestions.

Response:	
Bob Thomas - Illinois Municipal Electric Agency - 4 -	
Selected Answer:	No
Answer Comment:	Given the strongly supported rationale for deactivating the LSE registration function under the Risk-Based Registration initiative, Requirement 1.3 of BAL-005-0.2b should not be moved to FAC-001-3 as Requirement 7. The necessity of retaining this language for reliability purposes should be reconsidered. [Has there ever been a situation where Load was not within a BA metered boundary?] If this language is needed for reliability, an alternate functional entity should be identified.
Response to Comment:	Has there ever been a situation where Load was not within a BA metered boundary? The answer to this question is yes, but it is the wrong question. The correct question is, "Can the addition of a new load without notice to the BA affect the ability of a BA to perform its balancing function adequately and thus detrimentally affect reliability?" Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net

Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment: **Ameren supports MISO's comments for this question**

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6

Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA believes these requirements should be retired on the basis that they are covered by the data specification requirements of Board approved TOP-003-3. While it may be appropriate to include the concept of meters and BA metered boundaries in Facility interconnection requirements, as currently worded the proposed requirements do not fit with the purpose or applicability of FAC-001.

Response to Comment: In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

With moving BAL-005-0.2b R1 to FAC-001 R5 and R6, the requirement has shifted from being a Generator and Transmission Operator function to a Generator and Transmission Owner function. PJM questions and considers consequences with this change. PJM seeks clarity on the following topics:

Generation Owners, Transmission Owners, and Load-Serving Entities have no requirement to supply the Balancing Authority with data that affects the ACE calculation. PJM proposes the following changes to FAC-001 R5, R6, and R7:

R5. Each Transmission Owner with transmission Facilities operating in an Interconnection shall confirm that each transmission Facility is within a Balancing Authority Area’s metered boundaries. The Transmission Owner shall coordinate any changes caused to the ACE due to each transmission Facility with the impacted Balancing Authorities.

R6. Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area’s metered boundaries. The Generation Owner shall coordinate any changes caused to the ACE due to each generation Facility with impacted Balancing Authorities.

R7. Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. The Load-Serving Entity shall coordinate changes caused to the ACE due to each Load with impacted Balancing Authorities.

The LSE has been removed from the standard based on the RBR initiative.

Since Reporting ACE is made up of many components, including Net Actual Interchange (NIA), Balancing Authorities will be dependent on the Generator Owners, Transmission Owners, and Load-Serving Entities for this data. When ACE is impacted by the identified Interconnection Facilities, how should Reporting ACE be addressed by the Balancing Authority or Reliability Coordinator? If a Generator, Transmission Owner, or load-Serving Entity fail to confirm that each of their Facilities are within the Balancing Authority Area's metered boundaries, is the affected Balancing Authority responsible for calculating an accurate Reporting ACE?

It is the responsibility of all BAAs to calculate Reporting ACE correctly at all times. Absent of metering out generation, transmission or load which cannot be done without having an adjacent BAA involved, the metering of those entities is not used in the calculation of Reporting ACE. Though Reporting ACE may be accurate, the BA may not be capable of accurately estimating their resource requirements to balance Demand and generation. The LSE has been removed from the standard based on the RBR initiative.

What effects will this have on R5? Will the Balancing Authority be aware data from the Generator Owner or Transmission Owner are missing or invalid if the Generator Owner or Transmission Owner have not confirmed it?

	This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:	No
Answer Comment:	FAC-001 is about Facility Interconnection Requirements. In the application guidelines of FAC-001-2, it is mentioned that these requirements include metering and telecommunications and as such could be interpreted to already include a requirement of metering to the BA. Meeting of facility interconnection requirements however is the purpose of FAC-002-1. Therefore 2 options are available: 1. Modify the purpose of FAC-001 to include the GO, TO and LSE,DP or end-user meeting with facility interconnection requirements (whereas presently the purpose is only to make these requirements available) and add in section B, requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in R1 thru R4 (not only with the requirement of being within a BA's metered boundaries as is the case with Project 2010-14.2.1 proposal). Revise purpose of FAC-002-1 so that it addresses coordination studies rather than meeting facility connection and performance requirements. 2. Change the title of FAC-002 which presently is a bit at odds with its

Response:	purpose and add requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in FAC-001. The SDT has modified FAC-001 to address your concerns. The LSE has been removed from the standard based on the RBR initiative.

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer:	No
Answer Comment:	As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
Response to Comments:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

the NERC Glossary of Terms, Reporting ACE requires that, “All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.” In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1

Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment:

Duke Energy requests further clarification on how the drafting team anticipates an entity will be required to demonstrate compliance with R5. As written, it does not appear that the proposed Requirements and Measures are in alignment. Currently, the requirements state that an entity (TO, GO, LSE) must confirm that a Facility is within a Balancing Authority Area's Metered Boundary, however, the measure suggests that an entity should point to a procedure to demonstrate compliance with R5, R6, and R7. We suggest that the drafting team revise the Measures to better align with what is being asked in the requirements, perhaps stating that an attestation letter from the BA would be adequate to demonstrate confirmation that an entity's Facility is within a BA Area's Metered Boundary.

The SDT has modified FAC-001 to address your concerns. The LSE has been removed from the standard based on the RBR initiative.

Response:

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Answer Comment:	As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
Response to Comments:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

Response:	In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer:	No
Answer Comment:	**KCP&L believes moving BAL-005-02.b R1 to FAC-001 should be rejected; it is an attempt to shoe-horn Requirements into an unrelated Standard, or, at**

	best, marginally related Standard. The FAC-001 Standard relates to entities seeking to interconnect with the Bulk Electric System. The Proposed FAC-001-3 and its predecessor versions' Purpose declaration state, "To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information." It is unclear how Transmission Owners, Generation Owners, and Load-Serving Entities confirming they are within a Balancing Authority's metered boundaries relate to Generator Owners seeking interconnection with the Bulk Electric System. The FAC-001 Standard relates to new equipment planned to interconnect with the Bulk Electric System while BAL-005-02.b R1 relates to current and operational interconnections. Additionally, the SAR discusses moving the TOP, LSE, and GOP from BAL-005-02.b (See SAR, pp. 4-5) to the FAC Standards. It is unclear where the TOP duties under R1 landed. It didn't land in FAC-001. Granted, the SAR is a framework and not binding, the language suggests the SDT was uncertain where to "put" the R1 Requirement. However, the Proposed FAC-001-3 R5 Violation Severity Level states, "The Transmission Operators with Transmission Facilities operating in an Interconnection…" In consideration of the VSL language and the proposed FAC-001-3 not expressly applicable to Transmission Operators, KCP&L is concerned that moving BAL-005-02.b R1 to FAC-001, creates an unstated duty for Transmission Operators. Furthermore, the Proposed FAC-001-3 Purpose declaration is reiterated in Applicability Sec. 4.1.2.1., "Generator Owner with a fully executed

	Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system." **The FAC-001 Standard relates to new interconnects to the Bulk Electric System and should not be used as a landing pad for BAL-005 Requirements that no longer are relevant to BAL-005. KCP&L does not object to moving BAL-005 R1 to another Standard, but FAC-001 is not the appropriate Standard and the proposed changes should be reconsidered.** **Finally, in the event the changes to FAC-001-3 R5, R6, and R7 are endorsed by the stakeholders, KCP&L would ask language be added to FAC-001-3 to highlight it is applicable to new facilities, including the facilities identified in R5, R6, and R7.**
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1

	R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative. In FAC-001-2 R2, the words “upon request” are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, “Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.”

	How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:	Yes
Answer Comment:	We agree with moving BAL-005-0.2b Requirement R1 to FAC-001 standard. However, given the likely retirement of the LSE functional role consideration should be given in the SAR to making the requirement applicable to the DP functional entity role.
Response to Comment:	In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that

they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment: Load Serving Entity (LSE) function: NERC provided FERC with justification to retire BAL-005-0.2b Part R1.3 for the LSE function (LSE function deregistration). Adding LSE requirements to FAC-001 does not appear to align with NERC's justification and the intent to retire BAL-005-0.2b R1.3.

FAC-001 Table of Compliance Elements: R5 and R6 reference Transmission Operator and Generation Operator, instead of Transmission Owner and Generator Owner.

	The Purpose of FAC-001 is to "…make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information." Adding requirements to FAC-001 regarding metered boundaries appears to be misplaced. The proposed additions are ongoing requirements to confirm the metering of transmission facilities. The use of the word "confirm" is not the same as to establish the interconnection requirements.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without

advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer: No

Answer Comment: (1) FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC -001 were removed including a requirement for metering and telecommunication.

	Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R5, R6 and R7) does not resolve or address a reliability concern and would violate paragraph 81 criteria. Moreover GTC believe that requirements FAC-001-3-R5, R6 and R7 address specific needs for operating the system and therefore belong and already are included in Operations Standards such as TOP and IRO and not a Planning Standard associated with Facility interconnection Requirements. (2) As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring." TOP-003-3 applies to the same entities listed in the draft requirements.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a

	modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. In FAC-001-2 R2, the words “upon request” are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for

	interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, “Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.” How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:	No
Answer Comment:	We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

	the NERC Glossary of Terms, Reporting ACE requires that, “All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses.” In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment: The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

See file attached to Question 1 for the full text of the comments to Question 2

Response to Comment: Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Selected Answer:	No
Answer Comment:	The FAC-001 standard is used to facilitate interconnection requirements for those **entities seeking interconnection** into the **BES.** In the draft FAC-001-3 Requirements R5-R7 the language speaks to those who entities who are already operating in an interconnection and therefore does not fit the purpose of this standard. The FAC-001 standard cannot be used to enforce R5 –R7 for those facilities that already exist. The LSE function should not be included in the FAC-001 standard and therefore R7 should be removed in its entirety from the draft. In R7, it is not clear if the LSE, TO, or GO will be required to address this in their interconnection requirements. There is no requirement for an LSE to have documented facility interconnection requirements.
Response to Comment:	In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Answer Comment:	To truly make this consistent with the purpose of the FAC-001 standard the wording should be revised to address the documented facility interconnection requirements. The draft standard should require that the TO & Applicable GO facility interconnection requirements address BAA metered bounds for those entities seeking interconnection. The entities seeking interconnection should determine their operating area and therefore BAA metered bounds from their desired interconnection location. CSU is of the opinion that these requirements belong in the INT or TOP family of Standards.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: No

Answer Comment:

These requirements do not rise to the level of needing a continuously audited Reliability Standard. Once a facility is interconnected and certified, then the inclusion within a BA's metered bounds should be verified at that time. There should not be a need for continuing certification that it remains within the metered bounds. The requirements as stated only result in administrative efforts and are an exercise in submitting attestations.

One suggestion would be to simply add a sub-requirement that the Transmission Owner's Interconnection Requirements (FAC-001-3 R1) must include a requirement that all interconnected facilities must be demonstrated to be within a Balancing Authority's metered boundaries.   Then there would be no need for the new, proposed R5-R7. This puts the compliance effort into ensuring the facility is metered properly upon interconnection – to satisfy the TO Facility Interconnection

	Requirements – rather than an ongoing verification that the facilities continue to be within the metered bounds.
Response to Comment:	The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Response:	

Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	No
Answer Comment:	Reclamation recommends that the drafting team propose to retire BAL-005-0.2b R1 instead of moving the requirement into FAC-001-3. Reclamation does not believe that the drafting team has addressed the Periodic Review Team's recommendation to identify "what is needed for ensuring facilities are within a Balancing Authority Area prior to MW being generated or consumed." Like the existing requirement, the proposed requirement does not mention verifying that facilities are within the metered boundaries of a Balancing Authority Area "prior to transmission operation, resource operation, or load being served." Therefore, the proposed requirement perpetuates a paperwork burden that costs staff time and resources of Generator Operators, Transmission Operators, and Load Serving Entities with longstanding arrangements with their host Balancing Authority. Registered Entities acquiring letters to confirm that they are in the

	metered boundaries of a Balancing Authority Area provides no benefit to system reliability.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that

they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Andrew Pusztai - American Transmission Company, LLC - 1 -	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO	
Selected Answer:	Yes
Thomas Foltz - AEP - 5 -	
Selected Answer:	Yes
Leonard Kula - Independent Electricity System Operator - 2 -	

Selected Answer: Yes

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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

Selected Answer:	No
Answer Comment:	**MWHr meters are for Inadvertent Interchange accounting. Making this change will confuse the issue and will add unnecessary obligations. As long as the two BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole**. The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are: 1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.

	2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs. If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.
Response:	
Terry BIlke - Midcontinent ISO, Inc. - 2 -	
Selected Answer:	No
Answer Comment:	MWHr meters are for Inadvertent Interchange accounting. There are already other requirements proposed that deal with making sure ACE is realatively accurate. Additionally, as long as adjacent BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole. The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered

to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

MWHr meters are for Inadventent Interchange accounting. Making the proposed change could lead to confustion and unnecessary obligations. If the two BAs use common metering, any minor error in ACE reporting is contained and would have no impact on the Interconnection as a whole.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1

John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5

John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: Yes

Answer Comment: We concur with the SDT's recommendation, as BAL-005-1 addresses more proactive and real-time AGC operations while BAL-006 addresses more after-the-fact.

Thank you for your comments.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment: Texas RE noticed there is no redline for BAL-005-1. Redlines are helpful in reviewing revisions.

Texas RE noticed BAL-006-2 R3 has the phrase "with readings provided ***hourly***" (emphasis added) which, dictates a timing aspect. BAL-005-1 R1 has the phrase "to determine hourly megawatt-hour values" but does not have a time aspect specifically required. Texas RE inquires

	whether this was the intent of the SDT (and Texas RE is aware of the expected historical practice of hourly communications between entities). The SDT elected not to provide a red-line since it was not meaningful and more confusing. The Operating Process will determine the time-frame for distribution of the required information between adjacent BAAs.
Response:	
John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
David Jendras - Ameren - Ameren Services - 3 -	
Selected Answer:	No
Answer Comment:	**Ameren supports MISO's comments for this question**
	Please refer to the response to the MISO comments.
Response:	

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA agrees removing R3 from BAL-006, but it seems to have created duplicative requirements in BAL-005. Requirements R1 and R8 should be combined.

Response:	The SDT has modified the proposed standard to accommodate your recommendations.

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:	No
Answer Comment:	The standard states that the purpose is for acquiring data to calculate Reporting ACE. R1 does not fall under that category as it is currently written. It states its purpose is to determine MWh values. PJM suggests the following change to the R1 to align with the purpose of BAL-005: R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed- upon time synchronized common source. to determine hourly megawatt-hour values. While PJM agrees it is important to maintain a requirement to calculate MWh values for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard. The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is

required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 – NPCC

Selected Answer: No

Answer Comment: For the Quebec Interconnection, it makes more sense for metering issues to be in BAL-006 than BAL-005 since as a single BA asynchronous Interconnection, Net Interchanges are not calculated in our ACE. However HQ understands that our situation is exceptional and do not oppose the move of BAL-006-2 R3 to BAL-005-1.

Response: Thank you for your comment.

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments

Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy agrees with the move to BAL-005-1, however, we recommend that the drafting team revise the Measure for R1 to better align with R1.1. The sub-requirement R1.1 states that megawatt-hour values must be exchanged between Adjacent Balancing Authorities. The Measure provides guidance for R1, but does not provide guidance or example of demonstrating compliance with R1.1. More information is needed to outline how an entity is expected to demonstrate that the exchange of values took place, and how often must the exchange take place.**

Thank you for your comment. The SDT has made modifications to both the proposed standard and the measurements.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment: BAL-006-2--

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

Is there a requirement for hourly reporting? What is meant by "common"? Is this a certification issue, or an Interconnection Agreement issue, or a standard?

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment:

The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

See file attached to Question 1 for the full text of the comments to Question 3

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different

Response:	data comparisons for each Adjacent BAA for each tie line. These data comparisons are: 1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA. 2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs. If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: Yes

Answer Comment:

The change from BAL-006-2 R3 to BAL-005-1 R1 and R8 seem to be a step in the right direction. The measures however (BAL-005-1 M1) seems to only require evidence that a common source was agreed upon, not that the data values were actually exchanged between Adjacent BA's in a timely manner. If the intent is only to ensure a common source was identified, then that should be done in certification and does not rise to a Reliability Standard.

The need for common megawatt-hour meters between BAs serves only to account for inadvertent interchange between those entities. Accumulated inadvertent is not related to real-time reliability. Proposed BAL-005-1 R1 should be removed.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: none

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

Notwithstanding our comments on selected requirements provided below, as an overall comment we do not believe some of the proposed requirements belong to a Reliability Standard. We believe Requirements R2, R4, R5 and R6 are more suited for inclusion in the Organization Certification Requirement for Balancing Authorities since these requirements stipulate the capabilities and facilities that need to be in place to enable a BA to perform its tasks. These are "one-off" requirements that do not drive continuous behaviors, and they do not require frequent updates.

These requirements have been reviewed by the Periodic Review Team and found to be necessary to remain as Reliability Standard requirements. The Drafting Team concurs.

In response to the comment of lack of continuous behaviors and infrequent updates nullifying these requirements, the Drafting Team would ask what NERC procedural document is being referenced to determine these as thresholds for valid requirements. Many NERC requirements occur annually or upon request. Additionally, the Drafting Team does not agree that these are “one-off” requirements that do not need to be continually considered in the operation and maintenance of the systems used to operate the grid. For example, flagging inaccurate data and establishing a scan rate must be considered every time new data points are implemented.

If the Balancing Authority is not required to confirm the accuracy of their Frequency metering equipment at some reoccurring periodicity, it would eventually deteriorate and impact the accuracy of the Reporting ACE.

Similarly, if there is not a requirement to confirm availability of the system calculating Reporting ACE, there is no consequence for not maintaining such systems.

b. Requirement R4: The 99.95% uptime is overly prescriptive and there does not exist any technical justification. Unless supported by technical justification, this requirement should be removed. Further addition, the 0.001 Hz “accuracy” requirement is misleading. We suggest to replace "accuracy" with "resolution" to more properly convey the requirement.

The SDT believes "accuracy" and "resolution" conveys the same intent, however, the responses received did not support changing the term.

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

c. Requirement R5: We agree with the need to provide operating personnel with accurate information that supports awareness and calculation of Reportable ACE, but the examples listed places emphasis on the secondary information as it fails to capture the more important pieces of information which were listed in the existing BAL-005. We therefore suggest R5 be revised to:

R5. The Balancing Authority shall make available to the operator information associated

with Reporting ACE including, but not limited to, real-time values for ACE, Interconnection

frequency, Net Actual Interchange with each Adjacent Balancing Authority Area and quality flags indicating missing or invalid data.

The SDT believes such information is necessary for the operator to know at all times if its Reporting ACE is accurate and the reason for why it may not be accurate, since the operator is utilizing Reporting ACE to balance Demand and resources at all times to ensure a reliable Interconnection.

d. R6: As with our comments on R4, the 99.5% uptime is overly prescriptive and restrictive, and there does not exist any technical justification. A 99.5% uptime requirement means that all model builds and software glitches couldn't exceed 43.8 hours in any given year. This is overly restrictive. Unless supported by technical justification, this requirement should be removed.

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

e. R7: This requirement is not needed. R1 already stipulates the need to calculate and hourly megawatt-hour values (and Reporting ACE, as we suggested above); and R4 already stipulates the scan rate. Failure to meet either requirement will result in a BA being unable to comply with the standard in which case the BA must develop corrective actions to return to compliance. Having an explicit operating process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE is redundant to the combined requirements in R1 and R4. We therefore suggest to remove R7.

The SDT has combined R1 and R8 to help understand the requirements. In addition, the SDT has provided a detailed rational for the requirements including R7 "the Operating Process". The Drafting Team agrees that in the absence of significant meter error, R1 and R4 allows for accurate control of the grid. Unfortunately, if a significant meter error exists and goes unaddressed, there can be significant impact to the controlling of the grid during the operating hour not captured in Reporting ACE that is then absolved through the accounting process of reconciling Actual Net Interchange. In the absence of a requirement such as R7, there is no impetus for an entity to correct the meter error in a timely manner to resolve the problem.

If for whatever reasons R7 is retained, then the term "Operating Process" should not be capitalized since it is not a NERC defined term.

The Operating Process has been defined by NERC as, '' A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process."

f. R8: This requirement is implied in and redundant with, R1. Suggest to remove it.

The SDT has re-written and combined R1 and R8 as the new proposed R7 and has provided clarifying rationale.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:

See attachment with Strikethrough

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time sychnronized". AGC and ACE use real-time values, not hourly values.

The SDT has re-written and combined R1 and R8 as the new proposed R7 and has provided clarifying rationale.

There is a reliability need for a "mutually agreed upon" source of the data. Otherwise Adjacent Balancing Authorities cannot expect to control to the same values if the source of those values has not been confirmed to be common. The confirmation may only need to occur once or upon modification. But it impacts the reliability of the data being provided.

BAL-005-1

R1. Each Balancing Authority shall *ensure* **that have a process to operate to common, accurate** *each* **Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its** *an* **Adjacent Balancing Authorities**. *is equipped with a mutually*

	agreed upon time synchronized common source to determine hourly megawatt-hour values **The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1** **If the change to R1 above is made, R7 is no longer necessary.** **R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.** The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors. The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between

BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Answer Comment:

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time sychnronized". AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall have a process to operate to common, accurate Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its Adjacent Balancing Authorities.

The SDT appreciates the suggestion. Unfortunately, this proposed requirement language lacks specifics to what data (hourly versus instantaneous) is being exchanged.

The measure of this requirement should not be logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3

Thank you for your comment. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment:

The proposed R1 should be shortened and merged with R7. No mention of “mutually agreed upon” nor “time sychnronized” is necessary. AGC and ACE use real-time values, not hourly values.

We suggest the following:

BAL-005-1
R1. Each Balancing Authority shall have a process to operate to common, accurate Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its Adjacent Balancing Authorities.

The SDT appreciates the suggestion. Unfortunately, this proposed requirement language lacks specifics to what data (hourly versus instantaneous) is being exchanged.

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1.

R7 would not be necessary if the change to R1 above is made and R8 would be redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Thank you for your comment. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5

Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment:

1. We believe Requirement R1 should focus on detection and correction of a problem rather than a guarantee that a common source is available. This would better align with a risk-based approach that NERC is mandating during standard development. We believe this can be achieved by rephrasing the requirement to read
"Each Balancing Authority shall monitor mutually agreed-upon time-synchronized common source with Adjacent Balancing Authorities to determine hourly megawatt-hour values for each common Tie-Line, Pseudo-Tie, and Dynamic Schedule." We feel that by moving in this direction, the associated VSLs can be set to more adjustable criteria, such as the length of time between detection and correction, (e.g. under 30, 60, and 90 days).

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

2. We feel the SDT should align the VSLs for R2 to more performance-based criteria. We agree that six-seconds is a reasonable benchmark, but question if it needs to be categorized as a severe VSL. Instead, we recommend assigning a sliding time scale to each VSL (e.g. greater than or equal to 6 seconds, and greater than or equal to 12 seconds, etc.)
Thank you for your comment. The SDT has modified the requirement to provide additional clarity.

	2. In Requirement R3, the BA is expected to notify its RC within 45 minutes from the beginning of its inability to calculate Reporting ACE. If a BA encounters multiple instances when it is unable to calculate its Reporting ACE in a consecutive minute time period, but never haves an instance that is greater than thirty consecutive minutes, we want to confirm that the time period for notification begins with the first reportable instance. We believe this can be accomplished by replacing "an inability" with "the inability" at end of the requirement to read "…within 45 minutes of the beginning of the inability to calculate Reporting ACE." Thank you for your comment. The SDT has modified the requirement to provide additional clarity. 4. We believe System Operators should be identified in Requirement R5, as this is a NERC-defined Glossary Term. Moreover, it does not provide any ambiguity for auditors and better aligns with those personnel identified to complete training for reliability-related tasks in Reliability Standard PER-005-2. The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel. 5. For Requirement R5, we agree with the SDT's approach that Reporting ACE can be a primary metric to determine operating actions or instructions. Furthermore, System Operators should be aware of when such metrics are based on poor or insufficient data. However, we disagree with the SDT's approach taken in the wording of this requirement. Proof of the existence of a graphical display or dated alarm

	log, as mentioned as possible evidence for compliance, will only lead to confusion on how evidence should be presented. We believe rewording this requirement to "each Balancing Authority shall monitor the quality of information used to calculate its own Reporting ACE" achieves the intent of "making available" sufficient data to System Operators. The Drafting Team disagrees that language to direct the "monitoring" of data will result in invalid data being brought to the attention of an operator. Effective monitoring can only occur if one knows what represents invalid data, provided in this instance by the flagging. The purpose of the measurement is to demonstrate that if adequate flagging of invalid data exists, it would likely appear on an alarm log or graphical display. 6. We feel the SDT should provide rationale on the need for Requirement R6. While we agree that "Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection," we believe a requirement measuring the availability of a Reporting ACE calculation system is unnecessary. System Operators, when in distress, likely will rely on frequency meter measurements and communications with other Adjacent BAs when Reporting ACE is not available. This proposed standard already has an availability requirement listed in Requirement R4, and with a requirement that has a higher availability rate. We believe requiring a system be available should be reserved for the ERO Event Analysis Process, much like SCADA is for RCs and TOPs. Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

7. We believe the VSLs criteria for Requirement R7 could be more performance-based, particularly with how fast the BA took to mitigate errors affecting the scan-rate accuracy of data. We recommend sliding scale criteria, such as within 15 minutes, within 30 minutes, etc.

Unfortunately since the resolution of each meter error situation is unique depending on the size of the error, the criticality of the meter, the equipment availability, and meter location, the Drafting Team could not use timing as determinant. Since having a process is a true or false condition, it left only one VSL level.

8. In Requirement R8, we believe the requirement should focus on detection and correction to better align with a risk-based approach. We believe this can be achieved by rephrasing the requirement to read "Each Balancing Authority shall use a common source for Tie-Lines, Pseudo-Ties, and Dynamic Schedules with Adjacent Balancing Authorities when calculating Reporting ACE." We feel that by moving the requirement in this direction, the associated VSLs can be set to adjustable criteria, such as the length of time between detection and correction, i.e. under 15 minutes, under 30 minutes, etc.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

9. The data retention of the proposed standard, current year plus three years, is significantly larger than the one year retention found in the current standard and goes beyond the three-year audit cycle for BAs. In

	the context of a Risk-Based CMEP, we feel an entity should only need to retain one year's worth of data. There is minimal reliability benefit to requiring an entity to store data for longer than one year, especially considering the tools in place for the ERO to spot check or self-certify compliance activities more frequently than an audit. The current effective version of BAL-003-1 requires Balancing Authorities to retain current year, plus three calendar years of Reporting ACE data. 10. We believe the Implementation Plan should be updated to account for the retirement of IRO-005-3.1a, as Requirement R1.6 of that standard has the RC monitoring ACE and not Reportable ACE for all its BAs. The RC specifies the information to be supplied by the BAs. 11. The third bullet of the proposed definition for Automatic Time Error Correction, as listed within the Implementation Plan, has a typographical error and should reference ε10. Thank you. We will make that correction.
Response:	
Rachel Coyne - Texas Reliability Entity, Inc. - 10 -	

Answer Comment:

1. As stated in the answer to Question 1, Texas RE is concerned the SDT has not considered interconnections with a single BA. The initial SAR comments included the following statement: "Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception." It does not appear the SDT addressed the single-BA issue which results in the Reliability Standard not being applicable to the ERCOT and Quebec Interconnections. This, in turn, affects BAL-001 applicability. If Reporting ACE is not applicable to interconnections with a single BA, BAL-001 might not apply to the ERCOT and Quebec Interconnections. Additionally, any BA that connects with the ERCOT Interconnection BA will not be able to accurately determine Reporting ACE which could cause failure of BAL-001 for those BAs (assuming they utilize net interchange values in their Reporting ACE). This omission creates a reliability gap. Texas RE recommends including Interconnections with a single BA.

Reporting ACE has been redefined to require that all DC asynchronous tie lines with other interconnections be represented as Source-Sink pairs and excluded from Reporting ACE. The drafting team did this to insure that errors resulting from ties to other interconnections would not affect the quality of Tie Line Bias control. The contribution of DC flows from other interconnections is already included in the interconnection frequency, and therefore, there should be no adjustment for DC tie flows or DC schedules in Reporting ACE for single BA interconnections.

Reporting ACE for a single BA interconnection is defined as:

$RACE = (NI_A – NI_S) – 10B (F_A – F_S) + I_{ME}$

	Since there are no tie lines another BA on the same interconnection, the first term, $(NI_A - NI_S)$, becomes zero. Since there are no tie lines to another BA on the same interconnection, the third term also becomes zero. The leaves the Reporting ACE for the BA as: $RACE = -10B (F_A - F_S)$ This Reporting ACE is used in the CPS1 and BAAL requirements and must be calculated to determine compliance with those requirements although the actual value of Reporting ACE is not used because it is offset by other parts of the requirements. For example, in CPS1: $CPS1 = \{2 - [(RACE / -10B) \times (F_A - F_S)]/\varepsilon_1^2\} \times 100 = \{2 - [(F_A - F_S)^2 / \varepsilon_1^2]\} \times 100$ Thus final compliance is not dependent upon the Frequency Bias Term. The same is true for BAAL. 2. There seems to be some inconsistency with regards to definitions. For example, the definition of “Reporting ACE” in the Standard is different than the NERC Glossary of Terms (Glossary) but there is no redline. The definition of “AGC” is different from the Glossary and there is a redline. Is intent of the SDT to change both terms in the Glossary? Frequency Bias Setting is not defined within this Standard so it appears there is no change to that term. It is the intent of the Drafting Team to add or modify all terms listed under the “New or Modified Terms” section. 3. Asynchronous Ties should be included in the derivation of ACE where applicable. Without it, Reporting ACE will be off by the magnitude

		frequency applicable to the flows across a DC tie (especially if a trip of the DC occurs or an error in scheduling). In the definition of Reporting ACE asynchronous DC ties between Interconnections are excluded from Reporting ACE and are handled as either a generator or load.
	4.	Texas RE noticed the term "adjacent" is not capitalized in M1. Texas RE recommends removing "its" when describing "Adjacent Balancing Authority" as there could be more than one Adjacent Balancing Authority in M1. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. To make R5 consistent with the Purpose statement, Texas RE recommends changing "operator" to System Operator to be clear on which "operator" the information shall be made available. This change should also take place in the VSL for R5. The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.
	5.	Per the comment in Question 1, R7 should be for all BAs not just BAs "within a multiple Balancing Authority Interconnection". R7 should only be relevant to the area of the Balancing Authority that is

implementing an Operating Process.

The intent of the requirement is applicable only to BAAs operating in a multiple BAA Interconnection.

6. Texas RE noticed the VSL for R1 does not include language should include language for each Tie Line, Pseudo-Tie or Dynamic Schedule to *be equipped* with an agreed upon source to determine values. As is, the VSL ignores the "equipped" language within the Standard.

   The key elements of the requirement are the *agreement* of a *source providing hourly values*, which are addressed in the VSL. The Drafting Team does not believe the VSL language is unclear not having restated the word "equipped".

7. Texas RE noticed the VSL language for R3 does not include "for 30 consecutive minutes". Should there be a dash in "30-consecutive" in Requirement 3?

   Thank you for your comment. The SDT has modified the standard to address your concerns.

8.

   Texas RE recommends changing the verbiage from "each calendar year" to "annually" or for "each rolling 12 month period". Specifically, R4 and R6 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the

Evidence Retention statements. Texas RE would like the SDT consider whether this violates the RoP Appendix 4C Section 3.1.4.2 **Period Covered** “The audit period will not begin prior to the End Date of the previous Compliance Audit.”? Morever, does it cause a gap in compliance monitoring (and reflect a possible gap in reliability)?

Response:

Since an Audit Period will include at least one entire calendar year, the Drafting Team feels “calendar year” is a sufficient timeframe. Data Retention requirements in a standard can and often do differ from the Audit Period. This is for various reasons, often involving the magnitude of data that may need to be retained.

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment: **Ameren supports MISO's comments for this question**

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:	FMPA disagrees with the use of the term “accuracy” in R4.2. We believe the intent would be better described by the term “precision”, or perhaps “degree of accuracy”. The SDT believes “accuracy” and “precision” conveys the same intent, however, the responses received did not support changing the term. FMPA does not find any technical justification for the 99.5% availability requirement in R6, and believes it may be duplicative with BAL-001 and present a double jeopardy issue. With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. The availability of Reporting ACE is not duplicative of the requirements in BAL-001. BAL-001 requires a certain level of performance. That performance is calculated based on valid data. Any invalid data, such as unavailable Reporting ACE is to be excluded in its measurement. Therefore no double jeopardy exists.
Response:	

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:	Proposed Standard: Located in BAL-005-1 R1: R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed- upon time synchronized common source to determine hourly megawatt-hour values. 1.1. These values shall be exchanged between Adjacent Balancing Authorities. The phrase “Tie-Line” is not listed in the NERC Glossary, but instead “Tie Line” is listed. Definition: o Tie Line: • A circuit connecting two Balancing Authority Areas. Thank you. That correction will be made. The definition of “Pseudo-Tie” should be updated to include Reporting ACE if that is the purpose of the BAL-005-1 R1. Definition: o Pseudo-Tie: • A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes). Thank you. We will update the definition to reference Reporting ACE. If the SDT chooses not to change the language for R1, the language in R1.1

should be modified. With the current langauge the purpose of R1.1 is to exchange the hourly megawatt-hour values with the appropriate Balancing Authority to determine billing and Inadvertent Interchange. This should be stated more clearly as the current requirement has it written that the values are shared with [any] Adjacent Balancing Authority.

PJM proposes the following R1.1:
1.1. These values shall be exchanged for each Tie Line, Pseudo-Tie, and Dynamic Schedule shared between affected Balancing Authorities.

Response:

The SDTs intent with the old Requirement R1 is to ensure that the information is available to the BAs for use in the calculation of Reporting ACE. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Answer Comment:

• In the Mapping Document for BAL-005-1, R9, there appears to be a contradiction in the Description and Change Justification section about the HVDC links and their inclusion or not in Reporting ACE calculation vs the definitions of Scheduled and Actual Net Interchanges that exclude asynchronous DC tie-lines directly connected to another interconnection.

- R1 vs R8: HQ faila to see the difference between the 2 requirements. Perhaps the Rationales should be enhanced for a better understanding.

- M1 and M8 do not seem appropriate measures for an agreement on common metering or other sources. HQ suggesst favoring a written agreement rather than operator logs or voice recordings.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

- Even though HQ agrees that balancing authorities should use common metering equipment, we feel that R1 does not belong in BAL-005. This requirement relates to energy measurements that are used for accounting purposes and that do not come into play in reporting ACE calculation. This requirement should remain in BAL-006 and does not affect in any way automatic generation control. R8 does address perfectly the common metering needs between balancing authorities for real-time control.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Answer Comment:

For BAL-005, R8, “MW Flow Values” should be specifically mentioned in R8 and not just in the R8 Rationale.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5

Greg Cecil	Duke Energy	RFC	6

Answer Comment:

General comment: Duke Energy recommends the drafting team consider moving the proposed R8 to R2. We feel that based on the common subject matter of both of these requirements, that it would be more appropriate to have them consecutively listed within a standard.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

R4: Duke Energy requests further clarification regarding on how an entity may demonstrate compliance with R4.2 specifically. Also, more background information regarding where the 0.001Hz number came from and what it is measure against would add to clarity of the standard. Perhaps an Operating Guideline that provides guidance or examples on how an entity may demonstrate compliance, as well as a background on the 0.001Hz number.

Calibration testing can be performed and results provided as evidence. The measurement is taken directly from the existing R17 of BAL-005-0.2b. The SDT will present your suggestion to the NERC OC for consideration.

R5: We request further clarification on the use of the term operator in R5. Is this in reference to a System Operator, if so, we recommend stating so in the standard. As written, it appears that the standard is in conflict with the rationale for R5 which uses the term System operator.

Response:	The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.
Andrea Basinski - Puget Sound Energy, Inc. - 3 -	
Answer Comment:	As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE. If a Transmission Owner was required to state in their Interconnection requirements that transmission, generation, and load must be within the metered boundary of a BAA, it would put the onerous on the Transmission

Owner to enforce it. The reliability concern of these elements not being within a BAA is a NERC reliability concern and must be enforceable by NERC. It is not appropriate for a TOP to be responsible to arrange for the Balancing Authority arrangements for load, generation, and transmission facilities that they may not own. They have neither the authority nor obligation. That is why the applicability is placed on the owners and not the operators. The LSE has been removed from the standard based on the RBR initiative.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name:	NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Answer Comment:

In the Automatic Generation Control (AGC) definition consider removing “Automatically adjusts” and replace it with “determines”. The BA does not always have the capability of making an automatic adjustment. For example, a BA can send a requested loading value down through the RIG (Remote Intelligent Gateway) and have the local GO/GOP or DP/LSE with smaller units to meet the load, but do not have direct control over the units. It’s the local GO/GOP or DP/LSE who owns and/or operates the units that actually execute changes in loading.

	The SDT has modified the definition to address your concern. The LSE has been removed from the standard based on the RBR initiative. **Requirement R1** The use of the following text needs to be reconsidered: … each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent BA… … time-synchronized common source… … to determine hourly megawatt-hour values Pseudo-ties and Dynamic Schedules are not tie lines; they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE. The Drafting Teams is not certain if there is a question or comment being stated here. The phrase "time-synchronized common source" requires explanation. If two BAs are using a common source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly. The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias

Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Agree that Real-time metering of interties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing

	issue not a Real-time issue. R1 should be revised to clarify the intent. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors. Suggest that the Real-time installation of meters be left to BA Certification. The BA Certification process occurs one time. The installation or modification of meters occurs over a Balancing Authority's lifetime. **Requirement R2** What is meant by a 6 second sampling rate? Is that that the rate that a BA samples the data values it has at the moment, or does the 6 seconds represent a time delay between real-time and ACE calculations? This can be an issue for BAs that make use of multi-tier samples, where Owner X samples a group of resources every X-seconds, then sends that block of data to the BA who would sample all the blocks every Y-seconds. Traditionally, sampling rates were associated with how well a continuous function can be recreated. A sampling rate that is slower that the fundamental oscillations in the continuous function will not be able to reproduce that original function (the issue of aliasing as experienced in watching a TV program in which a wheel appears to rotate in the wrong direction). What is the reliability justification for this scan rate?

A critical component of the accuracy of Reporting ACE is the timeliness of the data sampled. Driving AGC using stale data would be counter-productive and could possibly create reliability problems. The requirement establishes a minimum threshold of how often the sampling must occur. Entities can chose to sample more often. As long as all data used to calculate Reporting ACE is sampled within six seconds, the source data should not introduce significant error.

Requirement R4

The value of monitoring system frequency is recognized, but again as suggested in our response to R1, the issue of frequency monitoring would seem to be better suited to a certification process rather than to a mandatory standard.

Balancing Authority Certification processes occur one time. The need for accurate frequency values consistently is an on-going real-time issue.

What is the justification for the values in Parts 4.1 and 4.2?

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

Requirement R5

The value of alarming is recognized, but given the fact that R5 could be a federal law, the question could be asked:

- What constitutes “quality” as in quality flags?

- What constitutes “invalid” as in invalid data?

The concern addressed in R5 (alarming) would be better addressed in certification. The systems that are certified should have alarming processes built into them, customized to the needs of the BA.

Each meter is unique in its capability and values it provides. It is upon the Balancing Authority to determine what values would be invalid for their operator to receive from their meters and what indications can be provided as a quality flag.

Requirement R6

Real-time errors in the ACE components are reflected in various other parameters:

1. System Frequency
2. Time Error (even if TE is not a standard is still computed)
3. End of Day checkouts
4. End of Month billing

As written R6 is an exercise is data collection and manipulation.

R6 does not represent any data collection and manipulation. It establishes the minimum availability of the system used to calculate Reporting ACE. The inability to calculate Reporting ACE creates a reliability risk to the grid.

	What are the implications of an unavailability less than 99.5%, and at what points are reliability impacted (and how)? With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability. **Requirement R7** Requirement R7 requires clarification. The process of monitoring for data errors and the process for mitigating errors that are identified are built into modern EMS systems. The requirement as written focuses only on errors "affecting the scan-rate accuracy of data used in the calculation of Reporting ACE…". As written, this is not all data used in ACE. Moreover, data does not impact the accuracy of the rate of scanning. The rate of scanning is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6, as modified) should contain all of the information used to identify and mitigate errors.

As written R7 does not rise to the level of a NERC standard and should be deleted.

The Drafting Team believes the absence of a requirement to address persistent meter error will allow significant meter error to remain in the calculation and control of the grid, creating burden on others.

The intent of R1 should be to ensure that a common metering point be identified for all Real-time inter-BA tie lines. The issue of Pseudo-Ties and Dynamic Schedules is really a business agreement between the two BAs in cooperation with the resource being used, and therefore is not a standard matter.

The issue being addressed in R1 in relation to Pseudo-Ties and Dynamic Schedules is their inclusion in Reporting ACE. This is particularly true of allocated shares of generation resources or supplementary regulation. If they are not included in Reporting ACE, the values will not be consistent and accurate.

Requirement R8

The requirement is on Pseudo-ties and Dynamic Schedules, but Pseudo-Ties and Dynamic Schedules are not tie lines, they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BA's ACE.

The Drafting Team is not sure if you are raising a question or concern. As you state, these values are necessary to be included in Reporting ACE and must originate from common sources for both Balancing Authorities to control to the same values.

The requirement to utilize a common source for all interties is a valid requirement.

The agreements referred to in R8 are Interconnection Agreements and therefore not a matter for a NERC standard.

Interconnection agreements are between the element owner and the Transmission Owner to whom they are interconnecting. This agreement of common source of Reporting ACE data must occur between Adjacent Balancing Authorities, who are not parties to the Interconnection Agreement.

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: **See file attached to Question 1 for the SRC comments on the rationale and language of several requirements.**

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: In general, BPA agrees with the current draft of BAL-005-1 but has some concerns with how BAs will meet the proposed R7 – relating to implementing an “Operating Process”. BPA believes that R7 is poorly written and needs to be revisited.

Response: Thank you for your comment. The SDT has made minor modifications to Requirement R7 reflecting other comments received, hopefully these modifications have provided the clarification necessary to address your concern.

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment: Identification of common sources of measurement (R8) and recording (R1) are BA certification items, not ongoing responsibilities that need to be checked periodically. New tie lines or "inputs" into the BA ACE calculations should be captured in FAC-001.

BA Certification occurs one time. New or modified tie-line values happen continually over the lifetime of a Balancing Authority. FAC-001 deals with Interconnection Requirements for Transmission Owners and Generator Owners. The need to have accurate Reporting ACE calculations is a real-time function that must occur to allow for adequate and accurate BAA control, as is the purpose of BAL-005.

There is continued confusion regarding the six second scan rate. A BA can demonstrate a scan rate of its received data every six seconds, but there is no requirement for the data "made available to" the BA to be scanned at a certain scan rate. To be more clear, the requirement should specify that "measurements should be made by the common source(s) and provided to the BA at least every six seconds for the calculation of Reporting ACE". At its worst, that should result in an ACE calculation being made and reported with data no longer than 12 seconds old.

Thank you for your comment. The SDT has modified the requirement to clarify our intent for this to be a design requirement and thus a capability requirement. Performance measurement associated with Reporting ACE is addressed in the other BAL standards.

The Rational for Requirement R3 leads with a sentence that has no basis in the Functional Model and should be deleted. The RC does not have responsibility "for coordinating the reliability of bulk electric systems for member BA's." The RC is responsible for "Mitigating energy and transmission emergencies" among other things. The statement made in the Rationale overstates the responsibility of the RC and minimizes the BA role. The BA has primary responsibility for maintaining load and generation balance and the RC has authority to step in and provide assistance if the BA is unable to maintain its obligations. Delete the first sentence of the Rationale for R3 box. What purpose does it serve to allow a BA an additional 15 minutes after 30 minutes of an inability to calculate ACE before notifying the RC. Delete “within 45 minutes of the beginning … ACE” and replace with “without delay”. As stated, the requirement would allow a BA to not calculate Reporting ACE for 44 minutes and then notify the RC. Or would require a BA that could not calculate Reporting ACE for 31 minutes but then was successful to also notify the RC. The intent of the change is not clear and seems to indicate a reduction in reliability.

“Without delay” in and of itself is not a measureable timeframe. Previously there was no limit on when the notification had to occur. The fifteen minutes after is a reasonable timeframe and improvement over no time limit.

What is the specific rationale for requirement of 99.95% (or 0.05% outage allowance = 43 seconds/day) uptime for frequency measurement? Is some reliability threshold crossed at 44 seconds of frequency measurement unavailability each day? Is the intent of R4.2 to still require calibration of the measurement or simply to utilize a provided significant digit of .001 Hz? The new R4 uses the term “accuracy” of .001Hz rather than the old R17 description of “<=0.001Hz”. Also the measurement M4 requires demonstration of “minimum accuracy” which lends itself to requiring a demonstrable calibration that is not specifically stated in R4. The intended statement in the mapping document for R17 to R4 is not captured well in the resulting R4.

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. Reporting ACE is an essential measurement of the BA’s contribution to the reliability of the Interconnection. Since Reporting

ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

Suggest deleting R5 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data. If kept, the Measure M5 includes an additional requirement that the suspect/garbage data indication should be indicated on BOTH the calculated Reporting ACE result as well as on the individual suspect/garbage data point. We suggest that R5 should include similar language to M5 if that is the intent. The RSAW should be adjusted based on changes to R5 or M5.

Thank you for your comment. The SDT believes that this requirement deals with flagging bad data used in the calculation of Reporting ACE.

Suggest deleting R6 as it is duplicative and in conflict with BAL-001-2. The reliability implication of "knowing" ACE is to be able to ensure balance is maintained. That is accomplished in CPS and BAAL and does not need to be duplicated here. The reporting % does not indicate a direct measurement of reliability and is administrative only.

BAL-001-2 measurements exclude values when Reporting ACE is not available. BAL-001-2 does not limit the unavailability of Reporting ACE. The SDT believes that R6 is necessary to provide reliable information to the BA which allows the BA to effectively control in order to balance Demand and resources at all time.

Suggest deleting R7 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data.

Thank you for your comment. The SDT believes that this requirement deals with flagging bad data used in the calculation of Reporting ACE.

Regarding R8: There is no demonstration of the reliability impact of using non-common meters between BA's for the purpose of Reporting ACE. In fact, in order to support reliability, the requirement should specify that redundant sources be made available to be used for Reporting ACE. Loss of the single, common source would result in lost input to the ACE calculation. A best practice that most BA's use is to identify a primary, common source for measurements and a secondary, common source for measurements and ensure each adjacent BA is using the same common source at the same time. *Common source measurements do not ensure accuracy, they just ensure the same error is introduced in both adjacent ACE calculations and therefore net each other out.*

The SDT agrees that a common source minimizes any error from impacting anyone other than the two Balancing Authorities it is between. The requirement does not disallow you from having more than one source for your meter data.

Response:

5. Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: none

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

We do not see the need to retain any of the BAL-006 requirements in a NERC Reliability Standard. Standard. Inadvertent Interchange is calculated for reconciliation purpose and as such, does not have any reliability value for real-time operations or post-mortem analysis. The facilities used for recording hourly Inadvertent Interchange are more suited to be stipulated in the BA's Organization Certification Requirements; the procedure to calculate, reconcile and resolve disputes over Intervertent Interchange can be put into operating guide or even in the NAESB's business practices.

Consistent with the risk-based principle, we suggest that unless there is clear demonstration that failure to calculate and reconcile Inadvertent Interchange can adversely affect operating reliability, this standard should be retired with its requirements transferred to other NERC and/or NAESB documents.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

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
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	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:

R1 is embedded in R2 and R3 and therefore unnecessary.

The sub-bullets of R3 should be bullets and not Requirements. Additionally, the end-of-day check should be an agreement of on and off peak totals, not hourly values. There are INT standards that require confirmation of hourly schedules.

In the compliance section, RROs do not fill out monthly summary reports and submit them to NERC.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment:

The sub-requirements of R3 should be bullets, not sub requirements.

The end of day check should be an agreement of on and off peak totals, not hourly values. Confirmation of hourly schedules are already required in other standards.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment: We appreciate the SDT's efforts to remove Requirement R3 from this standard.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment: In the revised language for BAL-006-3 R4, Texas RE recommends replacing the undefined term "Regional Reliability Organization Survey Contact" with Reliability Coordinator. This may be outside the purview of the SDT but consideration should be provided to clarify the responsibility while the Standard is being considered.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment: **Ameren supports MISO's comments for this question**

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Answer Comment: As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Response: Please reference our response to your comment in the FAC-001 question.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: The SRC recommends that BAL-006 be retired.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

See file attached to Question 1 for the full text of the comments to Question 5

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: None.

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment:

The purpose of BAL-006-2 (and resulting BAL-006-3) do not impact reliability. In fact, this enforceable Standard only serves to provide administrative metrics that are then used to facilitate either financial or in-kind reimbursements. In order to make this standard truly results based in relation to system reliability, requirements such as a BA shall not accumulate inadvertent interchange in excess of XX,XXX MWh per month would need to be created. No BA or RC will ever take reliability actions or issue Operating Instructions in relation to the accumulated or forecast accumulated inadvertent interchange. Resolution of inadvertent is an after-the fact reimbursement and not a reliability issue.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

6. Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 –

Answer Comment: none

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer Comment: In the "Table of Compliance Elements", the Violation Severity Levels, R5 and R6 should correctly refer to Transmission Owner and Generator Owner, respectively (instead of Transmission Operator and Generator Operator)

Thank you for your comment, the VSL has been corrected.

Response:

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Answer Comment: Dominion submitted comments - 2010-14_2_1_BARC-Unofficial_Comment_Form-20150715.docx

Response:

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment: APS agrees with moving these requirements from BAL-005 to the new FAC-001-3. APS also agrees with the proposed requirement language. APS does not agree that the measurements of these newly placed requirements have been correctly drafted.

A Transmission Operator, Generator Operator, or Load-Serving-Entity possessing the Facility interconnection requirements of the Transmission Owner they are attempting to interconnect with is not proof they are within a Balancing Authority Area. Evidence they are within a Balancing Authority Area

	would be demonstrated by possessing an executed Interconnection Agreement or similar contract. The measures will need to be corrected to reflect that. The RSAW will need to be corrected to line up with those changes.
Response:	The SDT agrees with you and has corrected the VSL and RSAW.

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:	**We concur with the proposed revisions to FAC-001-3.**
Response:	

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Answer Comment:	Do not change FAC-001 as this confuses the intent of the original requirement. There is virtually no way to prove that a particular component is within a BA. The original requirement was intended to be sure Control Areas balanced. This is done by operating to common ties and performing Inadvertent Interchange checkouts. The original intent of the requirements in BAL-005 was to assure all <u>Facilities</u> within the interconnected network are accounted for within the boundaries of a BAA, which allows for the BA to balance Demand and resources. The SDT will suggest additional language changes to FAC-001-3 to help clarify the issues.

Response:

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Answer Comment:

1) FAC-001-3 R5 Severe VSL should state "The Transmission Owner……" to match R5 which places responsibility for the requirement on the Transmission Owner. Currently the VSL states the Transmission Operator will comply.

2) FAC-001-3 R6 Severe VSL should state "The Generator Owner……" to match R6 which places responsibility for the requirement on the Generator Owner. Currently the VSL states the Generation Operator will comply.
Thank you for your comments, the SDT agrees with you and has corrected the VSL and RSAW.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1

John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment:

Should the SDT disagree that existing processes are adequate to accomplish the desired outcome (as described in the comments to Question #2), then the following is recommended:

1. Remove the inseration of 4.1.3 and R5-R7.
2. Modify R3.2 to read "Procedures for notifying the BA, TOP and RC of new or materially modified existing interconnections."
3. Modify R4.2 to read "Procedures for notifying the BA, TOP and RC of new interconnections."

Additionally, if possible, it is recommended that there be continued coordination with the FAC-001 team that produced FAC-001-2 in 2014 before any changes to FAC-001-2 are made.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The NERC staff assigned to this SDT is in continuous contact with the other SDTs.

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Answer Comment:

As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
The SDT has modified FAC-001-3 to clarify the issues. The LSE has been removed from the standard based on the RBR initiative.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment:

We believe FAC-001-3 should not be modified based on the reasons previously provided in question #2. We recommend the SDT retire the requirements moved from BAL-005-0.2b based on the reasons cited. At a minimum, we recommend the SDT provide technical justification on why these requirements are necessary.

The SDT's intent is to assure all Facilities within the interconnect network are accounted for within the boundaries of a control area and strongly feels the requirements are necessary to allow the BA to balance Demand and resources. The SDT has modified FAC-001-3 to help clarify the issues.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:	In R5, R6, and R7 it seems duplicitous to include, “metered boundaries” in the phrase “Balancing Authority Area’s metered boundaries” because the first sentence of Balancing Authority Area definition is “The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.” Texas RE noticed the Evidence Retention section does not address LSEs. Texas RE noticed the format of FAC-001-3 does not follow the new NERC Results Based Standards Template. Texas RE noticed the VSL for R5 refers to the “Transmission Operator” but the Requirement is applicable to the Transmission Owner. The VSL for R6 refers to the “Generator Operator” but the Requirement is applicable to the Generation Owner. The SDT agrees with your assertion that the use of “metered boundaries” may be duplicitous, however, the SDT believes the requirements are warranted. The information must be made available to all parties to assure balance of Demand and resources. The SDT believes that the requirement applies to all entities involved with generation or transmission. The LSE has been removed from the standard based on the RBR initiative. The SDT is aware of the formatting issue and will forward your comments regarding the format of FAC-001-3 to the NERC Standards Committee. The SDT agrees with your comment about the application to GO and has made the change as you suggested.

Response:

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Answer Comment: Please see comment under Qustion 2 above.

Response:

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment: **In our opinion there appears to be an inconsistency between the Standard and the Table of Compliance. The Applicability section 4.1.1 identifies the Transmission Owner as a Functional entity. Requirement R5 identifies the Transmission Owner with responsibility for confirming facilities are located within the BA boundaries. However, in the Table of Compliance Elements for requirement R5, the Transmission Operator is identified with this responsibility under the Severe VSL column. We believe that the Transmission Operator should be changed to Transmission Owner to be consistent with the requirements of the Standard.**

The SDT agrees with your comment about the application to GO and has made the change as you suggested.

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment: see question2

Response:

Scott McGough - Georgia System Operations Corporation - 3 -

Answer Comment:

1. R7 seems to not even fit with the stated purpose of FAC-001-3 for interconnecting (lowercase) to Facilities. What is the purpose of R7? Capitalized term "Interconnection" simply means "When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT." Reading the requirement at face value…if your load is anywhere in Eastern, Western , or ERCOT Interconnection area then confirm its in a BA Area's metered boundaries. Is the intent of R7 to identify **which** BA area the load is in? or is the intent to simply identify "yes" it is in "a BAs Area's metered boundary"? How does knowing or not knowing this have adverse impacts on the reliability of the BES with respect to the purpose of the standard?

In addition, note that from NERC's filing to FERC – *Supplemental Information to Petition for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards*, RM15-16, dated May 12, 2015 – NERC states that "An LSE does not own or operate Bulk Electric System facilities or equipment or the facilities or equipment used to serve end-use customers.21 (footnote 21 - The Distribution Provider is the functional entity that provides facilities that interconnect an end-use customer load and the electric system for the transfer of electrical energy to the end-use customer. If a company registered as an LSE also owned facilities, the company would be registered for other functions as well.

2. Measure M7 implies that LSEs have Facility interconnection requirements when there are no such requirements, thus complicating complying with R7. Does the drafting team intend for the LSE to provide a copy of the Facility interconnection requirements documents they may have received from the TO when requesting to interconnect to the transmission owner?

3. Depending on understanding the true intent of this requirement, we would be in favor for an attestation to be included in the measure, but then ... seems like a pointless, administrative requirement that meets P81.

Response:

1. The intent of this requirement is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.
2. The LSE has been removed from the standard based on the RBR initiative.
3. The SDT agrees with your comment.

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

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
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
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
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
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
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Answer Comment:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, suggest revising Requirement R7 to read "Each **Distribution Provider** that provides facilities that interconnect a customer Load shall confirm that each customer Load is within a Balancing Authority Area's metered boundaries." Measure M7 would need to be revised accordingly.

This standard is unnecessary given the fact that Interconnection Agreements are contractual legal documents that address and spell out the details addressed by the various FAC-001 requirements.

Also, the use of the requirement "shall address" is not a clear mandate and is open to interpretation by both the Responsible Entity and the Regional Enforcement entity.

The wording in Measures M5 thru M7 appear to have been copied from Measures M3 and M4, mentioning "dated, documented Facility interconnection requirements addressing the procedures" as evidence that the requirements are met. The wording in these Measures is appropriate for M3 and M4, but not M5 thru M7.
The LSE has been removed from the standard based on the RBR initiative.

The SDT disagrees with your assertion that this Requirement is not necessary. FAC-001-3 may require contractual legal documents but it does not insist that all elements of the Interconnection be included within the boundaries of a BA. The SDT has modified FAC-001-3 to help clarify the issues.

Response:

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Answer Comment:

In addition to the comments GTC listed in Question 2, GTC believes the response to R5 as a TO would simply be "yes" and is unaware how this answer enhances reliable operation of the BES. Therefore, GTC does not quite understand the intent of these requirements as they are written. Confirm which BA Area the Transmission Facility is located in? Confirm to whom? GTC see's this as administrative in nature subject to P81 criteria.

The original intent was to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA allowing for balance of Demand and Resources. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Answer Comment:

We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Answer Comment: Hydro One supports all comments provided by NPCC RSC regarding the draft of FAC-001-3.

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
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: The SRC recommends that FAC-001-2 be retired

See file attached to Question 1 for the full text of the comments to Question 6

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: None.

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3

Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Answer Comment:

Again to illustrate the comments in response #2, FAC-001 is a facility interconnection requirement standard so any changes here will be applied to FAC-001 applicable functional entities documented facility interconnection requirements. FAC-001 typically deals with **new interconnections**, so if the intent of the FAC-001-3 R5-R7 is to make sure all transmission, generation, and load are within a BAA metered bounds this is not the correct standard. R7 in its entirety needs to be moved to another standard since it is not clear which interconnection requirement it will fall under (i.e. TO and/or Applicable GO).

The FAC-001 standard can be used to require documented facility interconnection requirements to address BAA metered bounds for all entities **seeking to interconnect**. However to enforce this for BAA metered bounds for those facilities that already exist within FAC-001, the documented facility interconnection requirements would have to retroactively apply for those facilities that already exist. R5-R6 needs to be moved to another standard. The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment:

The first 4 requirements, which make up the existing FAC-001-2, are administrative and should be moved to certification review. The new R5-7 are necessary due to the removal from BAL-005. However as suggested earlier, those requiremetns should also be included in the TO's Facility Interconnection Requirement documents and do not necessarily need to be specific Reliability Standard Requirements. If R1-4 are kept, we recommend changing the phrase "shall address" in R1-4 to "shall include".

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation agrees with the periodic review team that it is important to verify facilities are within the metered boundaries of a Balancing Authority Area before they are operational, but believes that the requirement should be imposed through interconnection or service agreements rather than a reliability standard. As an alternative, FAC-001-3 R5 through R7 and M5 through M7 could be rephrased to require a one-time confirmation prior to a facility being placed in service.

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

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Additional comments submitted by Louis Slade - Dominion for Q6:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, Dominion suggests revising Requirement 7 to read "Each ~~Load-Serving Entity~~ **Distribution Provider** ~~with Load operating in an Interconnection~~ that provides facilities that interconnect an end-use customer load shall confirm that each end-use customer Load is within a Balancing Authority Area's metered boundaries. If this suggestion is accepted by the SDT, corresponding changes would need to be made to Measure 7.

Response: The LSE has been removed from the standard based on the RBR initiative.

Additional comments submitted by Emily Rousseau – MRO NSRF:

1. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments: It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

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

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

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

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

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

Comments:

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time synchronized". AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall ~~ensure that~~ have a process to operate to common, accurate ~~each~~ Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its ~~an~~ Adjacent Balancing Authorities. ~~is equipped with a mutually agreed upon time synchronized common source to determine hourly megawatt-hour values~~

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Additional comments submitted by ISO Standards Review Committee

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

Rationale:

1. The BAL-005 definitions should not include any references to Automatic Time Error Correction (I ATEC).

   BAL-005 is a NERC standard applicable to all Interconnections - not one of the many regionally-approved standards. This standard is approved for all BAs unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. As such, the SRC believes the definition and references to Automatic Time Error Correction (I_{ATEC}) should be deleted and left to the regionally-approved regional standard.

2. The following phrases / terms used in the proposed definition of AGC are ambiguous or not precise.

- Centrally located equipment

  This phrase should be deleted.

  There is no justification to link the definition of Automatic Generation Control (AGC) to a given location given that AGC is a process (software) not equipment (hardware).

- …that automatically adjusts…

  This phrase should be reworded.

  There is no direct link between an AGC signal and the response of a resource. As written the failure of a resource to respond to an AGC signal would constitute a violation on the part of the BA.

  It would be more correct to state that AGC "is used to adjust resources".

- …maintain Reporting ACE…

  This phrase should be deleted.

AGC is not designed for reporting purposes. AGC is designed to assist in the control of a BA’s balancing of its resources to its NERC mandated balancing obligations.

- Resources utilized under AGC…

  This sentence should be deleted.

  - AGC does not “utilize” resources, but – rather – evaluates resource utilization within a balancing Authority Area to ensure that load and resources remain in balance. More specifically, resources are an input to AGC.
  - The sentence itself is a partial list of supply resources and therefore not critical to defining the term itself.

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:

The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

Rationale: (also see response to Question 6 below)

1. BAL-005-0.2b R1 addresses AGC. R1.1 – R1.3 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
2. If R1 and its sub-requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

Rationale:
The SRC opposes this proposal for the following reasons:

1. The two standards address issues that are in two different time horizons (BAL-005 is a real time horizon (MW), while BAL-006 is an hourly horizon (MWhr). To combine the two standards into a single standard will confuse the objectives of each of these time horizons and the associated functions.
2. The collection of hourly (Inadvertent Interchange) data proposed by the transferred requirement (R3) does not affect the real time calculation of Reporting ACE. BAL-006 is a standard for Inadvertent Interchange which is an after-the-fact accounting function as opposed to BAL-005 which is about real-time reliability function.
3. Real time metering of interconnecting points is better handled as a certification issue given that such metering is relatively static and stable and does not require continuous the continuous review mandated by a reliability standard.
4. The objective of R3 is not clear as currently proposed. Specifically, it is unclear if R3 is meant:
   - As a procedural mandate that BAs use a single real-time point of metering for interconnection points used in the ACE calculation?
   - As a data reporting mandate on meters, that all interconnection point meters have the ability to compute hourly readings? or
   - As a data reporting mandate on BAs to communicate information on interconnection points once an hour to adjacent BAs (in which case there is a need for a time criteria – e.g. send the information within 4 hours of the clock hour).

Additionally, if Requirement R1 is meant as a data reporting requirement, it should have been considered for retirement under the Paragraph 81 concept. If not, additional clarification is needed, *e.g.*, is it a certification requirement that mandates hardware.

The SRC also notes that NERC's Independent Expert Review Panel recommended BAL-006 for retirement because "This is only for energy accounting. Covered by Tagging requirements."

4. Please provide any issues you have on this draft of the **BAL-005-1** standard and a proposed solution.

Comments:
The SRC provides comments on the rationale and language of several requirements below by requirement.

Requirement R1
The SRC recommends:
- The rationale for R1 be reconsidered and corrected.
- The references in R1 to "time-synchronized common source" and "hourly megawatt-hour values " be deleted.

Rationale
The SRC questions the following text in the proposed "*Rationale for Requirement R1*":
- The intent of R1 is to provide accuracy…
- R1 …used in… Reporting ACE, hourly inadvertent energy, and Frequency Response measurements
- It [R1] specifies need for …instantaneous and hourly integrated …tie line flow values
- Common data source requirements also apply …

The intent of R1 is not accuracy (common source metering does not address accuracy). The intent of R1 is to ensure a zero-sum data ensemble for all ACEs.

Contract-based billing meters used for Inadvertent Interchange are not necessarily the same as the real time common source meters used in ACE. The text of R1 is not precise in what is the specific objective for R1. The rationale states R1 is for instantaneous <u>and</u> hourly tie flow values but the text of R1 states it is "…to determine hourly megawatt-hour values."

The final sentence in the Rationale section regarding of other R1 applications is superfluous and should be deleted.

The SRC questions the following text:

- … time-synchronized common source…
- … to determine hourly megawatt-hour values

The phrase "time-synchronized common source" requires explanation.

If two BAs are using a common (MW) source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values (MWh) the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly.

The SRC agrees that <u>real time</u> (MW) metering of inter-ties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing issue not a real time issue. In short, the SDT is asked to rewrite R1 in a fashion that clarifies the intent.

<u>Requirement R2</u>

The SRC recommends:

- The rationale for R2 be reconsidered and revised.

<u>Rationale</u>

The proposed "*Rationale for Requirement R2*" overstates its justification. Specifically the rationale states that without frequency "…the BA operator will lack situational awareness and will be **<u>unable</u>** to make correct decisions when maintaining reliability."

The SRC does not agree that a BA would be "unable" to make correct decisions. The SRC acknowledges that decision-making regarding impacts on and the support for frequency may be more difficult. However, this difficulty does not threaten the reliability of the interconnection as tie line flows will still be monitored by TOPs and system frequency will be monitored by other BAs, TOPs and RCs.

Requirement R4
The SRC recommends that sub-requirements (4.1 and 4.2) be deleted.

Rationale:
The SRC recognizes the value of monitoring system frequency, but suggests that the monitoring of the availability and accuracy of frequency-monitoring equipment is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements would be better suited to be addressed as part of a certification process or in guidance documents than as a mandatory reliability standard.

In lieu of deleting the sub-requirements, the SRC requests the justification for the values in R4.1 and 4.2, and for the benefits to reliability that is to be obtained through the proposed requirements.

Requirement R5
The SRC recommends:

- R5 be addressed as part of a certification process.
- The rationale for R5 be reconsidered and revised.

Rationale
The SRC believes R5 (alarming) would be better addressed in certification than as part of a reliability standard that is subject to continuous review as a reliability standard requirement. The systems that are certified should have alarming processes built into them that are customized to the needs of the respective BA. Such systems, once reviewed, are relatively static and not subject to frequent modification. Additionally, although the SRC recognizes the values of alarming, it is concerned that, in the context of a mandatory reliability standard, subjectivity will be introduced regarding what constitutes "quality" for quality flags, and "invalid" for invalid data. Without an objective measure for the aforementioned terms, Requirement R5 loses any value as a reliability standard.

The proposed "*Rationale for Requirement R5*" states "When an operator questions the validity of data, actions **are delayed** and the probability of **adverse events** occurring **can increase**." While the above could be true, there is no objective evidence to support the statement and therefore the statement should be deleted.

Requirement R6
The SRC recommends requirement R6 be deleted.

Rationale
The SRC recognizes the value of monitoring ACE calculation, but suggests the monitoring of the availability of the software, etc. utilized to calculate ACE is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements are better addressed during the certification process and in guidance documentation than as part of a mandatory reliability standard.

The SRC is concerned that certain terms such as "available system" create ambiguity, e.g., what would constitute an "available system." Neither the requirement nor the measurement makes clear what an available system is nor when a system would be deemed unavailable, e.g., is a system "unavailable" to compute ACE if a single data sample is unavailable? Or when the entire system is unavailable.

Requirement R7
The SRC recommends:
- R7 be deleted.
- The rationale for R7 be reconsidered and revised.

Rationale
The SRC suggests that as written, R7 is an administrative requirement that does not rise to the level of a NERC standard and should be deleted.

Should Requirement R7 be retained, the SRC comments that the objective and obligation of a BA under requirement R7 is ambiguous and requires additional explanation/clarification. Additionally, the process of monitoring for and mitigating data errors that are identified are built into modern EMS systems. Thus, the SDT proposed requirement for an "Operating Process," which is not a defined term in Glossary and should not be considered a proper noun in this requirement, would be redundant of existing processes and functionality. Further, the requirement focuses only on errors "affecting the scan-rate accuracy of data used in the calculation of Reporting ACE…" The SRC asserts that data (in and of itself) generally does not impact the accuracy of the rate of scanning, which is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly.

The *Rationale for R7* states that "…Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system."

The SRC requests that either justification and support for this statement be provided, or the statement be deleted from the rationale section.

Requirement R8

The SRC recommends:

- R8 be reviewed and revised.
- The *Rationale for R8* be reconsidered and revised.

Rationale

The SRC believes that the issue of common source metering for all inter-ties, and of agreements on allocating resources as pseudo-ties or dynamic schedules is best handled as Interconnection Agreements or certification rather than as a reliability standard.

The SRC notes that Requirement 8 includes Pseudo-ties and Dynamic Schedules but Pseudo-ties and Dynamic Schedules are not tie lines, but are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE, and thus do not derive from common source meters.

The *Rationale for R8* states that "…When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action." The SRC objects to this statement.

If data sources are not common, then the ACE values in an Interconnection no longer form a zero-sum system. Such an error can only be identified in a tie-line by tie-line check. The result can be all BAs meet the Control Performance requirements, but the Interconnection itself is experiencing an imbalance that results in off-schedule frequency and time error. The SRC would point out that any inaccuracies or errors in the ACE components are reflected in various other parameters:

- System Frequency
- Time Error
- End of Day checkouts
- End of Month billing

Thus, no confusion would result and this should be deleted form the rationale
The *Rationale for Requirement R8* also states "The intent of Requirement R8 is to provide accuracy in the measurement and calculations." Common source metering does not provide accuracy as the data can still be in error. What common source metering does provide is a zero-sum system. Thus, the SRC requests that the rationale be modified to more accurately reflect the impact of data sources on accuracy.

5. Please provide any issues you have on the proposed change to the **BAL-006-3** standard and a proposed solution.

Comments:
The SRC recommends that BAL-006 be retired.

Rationale:
Inadvertent Interchange is an accounting metric not reliability metric.

The BAL-006 requirements are administrative mandates related to after-the-fact accounting should be retired under Paragraph 81.

Any value of Inadvertent Interchange is as an internal control process and would best be memorialized in a form other than a standard.

6. Please provide any issues you have on the proposed change to the **FAC-001-3** standard and a proposed solution.

   Comments:
   The SRC recommends that FAC-001-2 be retired (also see response to Question 2 above)

   Rationale:
   1. Requirements R1 – R4 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
   2. Requirements R5-R7 are certification issues. If these requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR Posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

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:

> **Rationale for Modification of AGC:** The original definition of AGC reflects "how to" control and automatically adjust equipment in a Balancing Authority Area and does not reflect the current technology nor the evolution of the industry from a “Control Area” to a “Balancing Area”. In addition, it was telling the entity "how to do it" rather than allowing the entity to perform the necessary functions in the most effective and reliable manner.
>
> The new definition reflects a process and allows the entity the flexibility to perform the necessary function in the most effective and reliable manner to address such process without being instructed on "how to do it".

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas’ Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

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

The absolute value of I_{ATEC} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \le L_{max} \le L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$PII_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ PII_{accum}^{on/offpeak} + PII_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Rationale for Modification of Balancing Authority: The SDT has recommended to change the definition of Automatic Generation Control (AGC) and to be consistent, with the change to AGC, the SDT recommends changing the definition of a Balancing Authority. In addition, Project 2015-04 Alignment of Terms SDT brought to our attention of the inconsistent use of "load-interchange-generation" and through the Alignment of Terms project it was recommend a SDT associated with a BAL Standard address the issue. The proposed changes reflects a Balancing Authority.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan-rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- **7.1.** a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,
- **7.2.** a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstratea common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of the	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.

			inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R7.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a common source for Tie-Lines, Pseudo-ties and Dynamic

						Schedules with its Adjacent Balancing Authorities **Or** **The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	

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

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

This is the first posting of the draft standard for a 45-day formal comment period with an initial ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR Posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

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:

Rationale for Modification of AGC: The original definition of AGC reflects "how to" control and automatically adjust equipment in a Balancing Authority Area and does not reflect the current technology nor the evolution of the industry from a “Control Area” to a “Balancing Area”. In addition, it was telling the entity "how to do it" rather than allowing the entity to perform the necessary functions in the most effective and reliable manner.

The new definition reflects a process and allows the entity the flexibility to perform the necessary function in the most effective and reliable manner to address such process without being instructed on "how to do it".

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas’ Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. ~~Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority’s interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.~~

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$.

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

- L_{max} is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \le L_{max} \le L_{10}$.
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual

Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections ~~with multiple Balancing Authority Areas~~ 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' ~~control~~ Reporting ACE equation~~s~~ (or alternate control processes).

Rationale for Modification of Balancing Authority: The SDT has recommended to change the definition of Automatic Generation Control (AGC) and to be consistent, with the change to AGC, the SDT recommends changing the definition of a Balancing Authority. In addition, Project 2015-04 Alignment of Terms SDT brought to our attention of the inconsistent use of "load-interchange-generation" and through the Alignment of Terms project it was recommend a SDT associated with a BAL Standard address the issue. The proposed changes reflects a Balancing Authority.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource~~load-interchange-generation~~ balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

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:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

~~**Rationale for Requirement R1:** Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data (meaning data from the same source) is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.~~

~~The intent of Requirement R1 is to provide accuracy in the measurements and calculations used in Reporting ACE, hourly inadvertent energy, and Frequency Response measurements. It specifies the need for common metering points for instantaneous and hourly integrated values for the tie line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply when more than two Balancing Authorities participate in allocating shares of a generation resource or in supplementary regulation, for example.~~

~~**R1.** Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed-upon time synchronized common source to determine hourly megawatt-hour values. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**1.1.** These values shall be exchanged between Adjacent Balancing Authorities.~~

~~**M1.** The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to determine if the Balancing Authority and its adjacent Balancing~~

~~Authority have agreed upon a time synchronized common source to determine megawatt-hour values.~~

Rationale for Requirement R1~~2~~: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

~~R2.~~R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M2.~~M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2~~3~~: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

~~R3.~~R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the~~an~~ inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M3.~~M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the~~an~~ inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3~~4~~: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

~~R4.~~R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~4.1.~~3.1. that is available a minimum of 99.95% for each calendar year; and,

~~4.2.~~3.2. with a minimum accuracy of 0.001 Hz.

~~M4.~~M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R34.

Rationale for Requirement R4~~5~~: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

~~R5.~~R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~M5.~~M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5~~6~~: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

~~R6.~~R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

~~M6.~~M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6~~7~~: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

~~R7.~~R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the ~~scan-rate~~ accuracy of scan- rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

~~M7.~~M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6~~7~~ and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7~~8~~: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action. The intent of Requirement R7~~8~~ Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the tie-line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example. The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors

in the scan-rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with:~~Each Balancing Authority shall agree with an Adjacent Balancing Authority on a common source for respective Tie-Lines, Pseudo-Ties, and Dynamic Schedules and shall implement that common source to provide common information to both Balancing Authorities for the calculation of Reporting ACE.~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a ~~mutually agreed-upon~~ common source to provide ~~common~~ information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a ~~mutually agreed-upon~~ time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

~~M8.~~M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstrate~~determine if it agreed with its adjacent Balancing Authority on a~~a common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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
None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1.~~	~~Operations Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to agree upon a time synchronized common source for hourly megawatt hour values with its Adjacent Balancing Authorities~~ ~~Or~~ ~~The Balancing Authority failed to provide the megawatt hour values to its Adjacent Balancing Authorities.~~
R1~~2~~.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to

						calculate Reporting ACE.
R2~~3~~.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of the~~an~~ inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 50 minutes from the beginning of the~~an~~ inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 55 minutes from the beginning of an inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of an inability to calculate Reporting ACE but notified its Reliability Coordinator in less than or equal to 60 minutes from the beginning of an inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of an inability to calculate Reporting ACE.
R3~~4~~.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency

			99.94 % of the calendar year.	99.93 % of the calendar year.	99.92 % of the calendar year.	metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4~~5~~.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with Reporting ACE to its operators.
R5~~6~~.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.

R6~~7~~.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing A~~a~~uthority failed to implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE.
R7~~8~~.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use~~agree upon~~ a common source for ~~t~~Tie-~~l~~Lines, Pseudo-ties and Dynamic Schedules with its Adjacent Balancing Authorities Or ~~The Balancing Authority failed to implement the common source to provide common information to both Balancing Authorities.~~

						~~Or~~ -The Balancing Authority failed to use~~agree upon~~ a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	

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[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

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

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014
Standard posted for 45-day comment and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

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: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

- **3.1.** Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).
- **3.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.
- **3.3.** Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

- **4.1.** Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3.
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

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

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014
Standard posted for 45-day comment and initial ballot	July 30, 2015

Anticipated Actions	Date
45-day formal comment period with additional ballot	November 2015 – January 2016
Final ballot	January 2016
NERC Board adoption	February 2016

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: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

    4.1. Functional Entities:

    4.1.1 Transmission Owner

    4.1.2 Applicable Generator Owner

    4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

    ~~**4.1.3** Load Serving Entities~~

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

~~**R5.** Each Transmission Owner with Transmission Facilities operating in an Interconnection shall confirm that each Transmission Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M5.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R5.~~

~~**R6.** Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M6.** Each Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R6.~~

~~**R7.** Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. *[Violation Risk Factor: Medium] [Time Horizon: Long-Term Planning]*~~

~~**M7.** Each applicable Load Serving Entity shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R7.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity~~Transmission Owner and applicable Generator Owner~~ shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

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				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
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~~R5~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator with Transmission Facilities operating in an Interconnection failed to ensure that those Transmission Facilities were included within metered boundaries of a Balancing Authority Area.~~
~~R6~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Generation Operator with generation Facilities operating in an Interconnection failed to ensure that those generation Facilities were included within metered boundaries of a Balancing Authority Area.~~
~~R7~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Load-Serving Entity with Load operating in an Interconnection failed to ensure that those Loads were included within metered boundaries of a Balancing Authority Area.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

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Version History

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1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
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2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I}_{ATEC}$ shall not exceed L_{max} .

$\mathbf{I}_{ATEC}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I}_{ATEC}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 will be retired concurrently with the effective date for BAL-005-1 . Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

after the effective date of the applicable governmental authorities order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of Automatic Generation Control, Pseudo Tie and Balancing Authority shall be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

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Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I}_{ATEC}$ shall not exceed L_{max} .

$\mathbf{I}_{ATEC}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I}_{ATEC}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections ~~with multiple Balancing Authority Areas~~ 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. ~~Centrally located equipment Equipment that automatically adjusts resources generation in a Balancing Authority Area from a central location to help maintain the Reporting ACE of a Balancing Authority's Area within the bounds required under the NERC Reliability Standardsinterchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction. Resources utilized under AGC may include, but not be limited to, conventional generation, variable energy resources, storage devices and loads acting as resources, such as Demand Response.~~

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' ~~control~~Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource~~load-interchange-generation~~ balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, ~~BAL-005-1 **will implemented concurrently with**~~ FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective~~,~~ as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 will be retired concurrently with the effective date for BAL-005-1 ~~"Prerequisite Approvals" section above~~. Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the effective date of the ~~that this standard is approved by~~ applicable governmental ~~regulatory~~ authorities order approving the standard, or as otherwise provided for ~~in a jurisdiction where approval~~ by the ~~an~~ applicable governmental authority ~~is required for a standard to go into effect~~.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, ~~the standard~~ shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of ~~Reporting ACE and~~ Automatic Generation Control, Pseudo Tie and Balancing Authority shall ~~should~~ be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

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Implementation Plan

Reliability Standard BAL-006-2

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2 will be retired concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2 shall be retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

Implementation Plan

Reliability Standard BAL-006-2~~3~~

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A~~BAL-006-3 – Inadvertent Interchange~~

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2~~3~~ will be retired~~implemented~~ concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2~~3~~ shall be~~come effective~~ retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

~~**Retirements**~~

~~BAL-006-2 (Inadvertent Interchange) shall be retired immediately prior to the Effective Date of BAL-006-3 (Inadvertent Interchange) in the particular jurisdiction in which the revised standard is becoming effective.~~

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Implementation Plan

Reliability Standard FAC-001-3

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- FAC-001-3 – Facility Interconnection Requirements

Requested Retirement

- FAC-001-2 – Facility Interconnection Requirements

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

Background

Reliability Standard FAC-001-3 addresses Facility Interconnection Requirements, which ensure the avoidance of adverse impacts on the reliability of the Bulk Electric System by requiring Transmission Owners and applicable Generator Owners to document and make Facility interconnection requirements available so that entities seeking to interconnect will have necessary information. Reliability Standard FAC-001-3 and associated Implementation Plan was developed in conjunction with BAL-005-1 (Balancing Authority Controls) to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented concurrently with BAL-005-1, as reflected in the "Prerequisite Approvals" section above.

Effective Dates

FAC-001-3 shall become effective on the effective date of BAL-005-1.

Retirements

FAC-001-2 (Facility Interconnection Requirements) shall be retired immediately prior to the Effective Date of FAC-001-3 (Facility Interconnection Requirements) in the particular jurisdiction in which the revised standard is becoming effective.

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Unofficial Comment Form

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Do not use this form for submitting comments. Use the electronic form to submit comments on the draft standards **BAL-005-1 – Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements**, and the recommended retirement of **BAL-006-2 – Inadvertent Interchange**. The electronic form must be submitted by **8 p.m. Eastern, Monday, January 11, 2016.**

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

On September 19, 2013, the NERC Standards Committee appointed ten subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT).[1] As part of its review, the BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-005-0.2b and BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. The recommendations of the BARC 2 PRT are in the Periodic Review Templates and SAR.

The Standards Committee approved a revised SAR that was posted for a 30-day comment period from July 16, 2014 through August 14, 2014. The BARC Phase 2.1 standard drafting team (BARC 2.1 SDT) reviewed the comments received from the SAR posting and developed revisions to BAL-005-0.2b, BAL-006-2 and FAC-001-2 standards. The standard were posted for a 45-day comment period and initial ballot from July 30, 2015 through September 14, 2015. The BARC 2.1 SDT also issued a survey to the industry to gather additional information concerning the disposition of the remaining requirements in BAL-006-2. Based on industry comments the BARC 2.1 SDT is proposing additional modifications to the definition of Automatic Generation Control (AGC) and Pseudo Tie, as well as additional modifications to BAL-005 and FAC-001 and retirement of the remaining requirements of BAL-006. With the retirement of the BAL-006 standard the BARC 2.1 SDT is also proposing to develop a Inadvertent Interchange Guideline.

This project addresses directives from FERC Order 693, and provides additional clarity to many requirements, as well as retiring requirements that meet the criteria developed in the Paragraph 81 project.

[1] The Standards Committee subsequently appointed an eleventh SME to the BARC 2 PRT.

Questions

1. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No

   Comments:

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

   Comments:

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below.

   Comments:

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

   Comments:

Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	Requirement R1 Part R1.1 and Part R1.2 have been moved into FAC-001-2 Requirement R3 and R4. Requirement R1 Part R1.3 is being retired.	Requirements R1 Parts R1.1 and R1.2 do not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system. Requirement R1 Part 1.3 is being retired in conjunction with the Risk-based Registration initiative de-certifying the LSE function.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R2	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R2.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R1 and Part 8.1 was moved into Requirement R3	The body of this requirement has been moved to Requirement R1 and Part 8.1 has been moved into Requirement R3.
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R7 ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed "how" to implement the HVDC link, but allowed to decide the method it will use.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R7	This requirement has been moved to Requirement R7.
BAL-005-0.2b R13	Moved to Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R7. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R4 and Requirement R7	This requirement has been moved into Requirement R4 and Requirement R7.
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality. In addition, proposed R3 requires a performance level that the Balancing Authority Area must meet. The standard does not tell the BAA how to meet it.
BAL-005-0.2b R16	Moved to Requirement R4	This requirement has been moved into Requirement R4.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R3)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R3.

Project 2010-14.2.1 Mapping Document
Transition of BAL-005-0.2b to BAL-005-1

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-1 R1	~~This~~ Requirement R1 Part R1.1 and Part R1.2 have~~has~~ been moved into FAC-001-2 Requirement R3~~5~~ and~~,~~ R4~~6~~.~~, and R7~~ Requirement R1 Part R1.3 is being retired.	~~This r~~Requirements R1 Parts R1.1 and R1.2 do~~es~~ not provide for necessary information concerning the calculation of Reporting ACE. The requirement provides for information necessary when connecting to the electric system. Requirement R1 Part 1.3 is being retired in conjunction with the Risk-based Registration initiative de-certifying the LSE function.
BAL-005-0.2b R2	Retired	This requirement was retired as part of the original Paragraph 81 project. Its retirement was approved by FERC effective January 21, 2014.
BAL-005-0.2b R3	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.
BAL-005-0.2b R4	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.

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Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R5	Retire	This requirement can be retired since coordination of common values between Adjacent BAs is covered in the Requirement R7~~1 and Requirement R8~~.
BAL-005-0.2b R6	Moved to definition of Reporting ACE and Requirement R2~~3~~	The portion of the requirement concerning calculating ACE was moved into the definition for Reporting ACE. The portion of the requirement concerning an entity's inability to calculate Ace for more than 30 minutes was moved into Requirement R2~~3~~.
BAL-005-0.2b R7	Retire	This requirement should be retired under Paragraph 81 criteria. The first sentence covers having a functional EMS or other system capable of calculating Reporting ACE and controlling resources, though resources can be dispatched manually without any detriment to reliability. The SDT believes that the term "operate AGC" in R7 refers to the capability to continuously calculate ACE, not automatic control of resources to the extent BAs cannot take resources off "AGC" mode.
BAL-005-0.2b R8	The body of this requirement was moved to Requirement R1~~2~~ and Part 8.1 was moved into Requirement R3~~4~~	The body of this requirement has been moved to Requirement R1~~2~~ and Part 8.1 has been moved into Requirement R3~~4~~.

Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R9	Retire	R9 is covered in the definition of Reporting ACE, and the proposed R7~~1~~ ensures that the BA does not include any Interchange in its Reporting ACE that does not have an Adjacent BA. Regarding R9.1, the Actual Net Interchange and Scheduled Net Interchange values in the Reporting ACE calculation include provisions for the Balancing Authority to include its high voltage direct (HVDC) link to another asynchronous interconnection. By assuring the values are handled consistently in the actual and scheduled Interchange terms included in the real-time Reporting ACE by definition, the Balancing Authority is not being instructed “how” to implement the HVDC link, but allowed to decide the method it will use.
BAL-005-0.2b R10	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R11	Retire	The basics of this requirement is factored into the definition of Scheduled Net Interchange (NIS) used in the Reporting ACE calculation as defined in the NERC Glossary.
BAL-005-0.2b R12	Moved to Requirement R7~~1~~	This requirement has been moved to Requirement R7~~1~~.
BAL-005-0.2b R13	Moved to ~~Requirement R1 and~~ Requirement R7	The portion of the requirement concerning common time synchronization was moved into Requirement R7~~1~~. The portion of the requirement concerning an equipment error was moved into Requirement R7.
BAL-005-0.2b R14	Moved to Requirement R4~~5~~ and Requirement R7~~8~~	This requirement has been moved into Requirement R4~~5~~ and Requirement R7~~8~~.

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Standard: BAL-005-1 – Disturbance Control Standard		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-005-0.2b R15	Retired	This requirement is duplicative of the intent of EOP-008 - Loss of Control Room Functionality. In addition, proposed R3 requires a performance level that the Balancing Authority Area must meet. The standard does not tell the BAA how to meet it.
BAL-005-0.2b R16	Moved to Requirement R4~~5~~	This requirement has been moved into Requirement R4~~5~~.
BAL-005-0.2b R17	Partially retired (partially captured in new Requirement R3~~4~~)	This requirement which address accuracy of RTU and transducers is meaningless in today's world. RTUs do not quantize measurement anymore, these are done by relay or meters. Transducers are not used anymore and have been replaced by meters and relays which measure quantities. This requirement should be restored such that it actually supports an accurate calculation of ACE and proper operation of AGC by specifying accuracy requirements for all telemetry associated with ACE (Frequency, MW and the associated sensing devices and telemetry). In addition, the interpretation effective 8/27/2008 in BAL-005-0.2.b for R17 states that this requirement is specific to the equipment used to determine the frequency component required for reporting ACE. This is now being captured in Requirement R3~~4~~.

Project 2010-14.2.1 Mapping Document
Transition of BAL-006-2

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R2	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R3	Moved to BAL-005-1 Requirement R7	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.
BAL-006-2 R5	Retired	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.

Standard: BAL-006-2 – Inadvertent Interchange		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification

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Project 2010-14.2.1 Mapping Document
Transition of BAL-006-2 ~~to BAL-006-3~~

Standard: BAL-006-2~~3~~ – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R1	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~
BAL-006-2 R2	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~
BAL-006-2 R3	Moved to BAL-005-1 Requirement R7~~1 and Requirement R8~~	This requirement directly impacts the ability to calculate an accurate Reporting ACE value.
BAL-006-2 R4	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~

Standard: BAL-006-2~~3~~ – Inadvertent Interchange		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
BAL-006-2 R5	Retired~~No change~~	The SDT is recommending this requirement be retired. This requirement is completely administrative in nature. It meets the Paragraph 81 criteria and is in agreement with the Independent Experts review findings.~~No change~~

Project 2010-14.2.1 Mapping Document
Transition of FAC-001-2 to FAC-001-3

Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R3 Part 3.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R4 Part 4.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.

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Project 2010-14.2.1 Mapping Document
Transition of FAC-001-2 to FAC-001-3

Standard: FAC-001-3 – Facility Interconnection Requirements		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
FAC-001-2 R1	No change	No change
FAC-001-2 R2	No change	No change
FAC-001-2 R3	No change	No change
FAC-001-2 R4	No change	No change
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R3~~5~~ Part 3.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
BAL-005-0.2b R1	Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R4~~6~~ Part 4.3	This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.
~~BAL-005-0.2b R1~~	~~Moved from BAL-005-0.2b Requirement R1 to FAC-001-3 R7~~	~~This requirement was moved from BAL-005-0.2b since it does not provide for information regarding the calculation of Reporting ACE. The requirement is more in line with facilities attaching to an interconnection.~~

Violation Risk Factor and Violation Severity Level Assignments

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

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-005-1, Balancing Authority Control. 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-005-1:
There are seven requirements in BAL-005-1. All of the requirements were assigned a "Medium" VRF.

VRF for BAL-005-1, Requirement R1:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. Requirement R1 is similar in scope to Requirement R3 and Requirement R5. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R8.
- FERC Guideline 3 — Consistency among reliability standards exists. This requirement is identical to the current enforceable BAL-005-0.2b Standard Requirement R8 which has 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 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-005-1, Requirement R2:

- FERC Guideline 2 — Consistency within a reliability standard exists. The requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF for BAL-005-0.2b Requirement R6.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is identical to the current enforceable BAL-005-0.2b standard Requirement R6 which has 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 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-005-1, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R8.1.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has 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 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-005-1, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b standard Requirement R8.1 which has 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 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-005-1, Requirement R5:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R3 which has a 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 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-005-1, Requirement R6:

- FERC Guideline 2 — Consistency within a reliability standard exists. This requirement does not contain sub-requirements. All of the requirements in BAL-005-1 are assigned a "Medium" VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to BAL-005-0.2b standard Requirement R7 which has a 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 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-005-1, Requirement R7:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in BAL-005-1 are assigned a "Medium" VRF. This is also consistent with the current FERC approved VRF in BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has a Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher VRF.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable BAL-005-0.2b Requirement R12 which has an approved Medium VRF and BAL-006-2 Requirement R3 which has an approved Lower VRF. However, the SDT felt that this requirement was not purely an administrative requirement and therefore deserved a higher 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 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-005-1 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-005-1 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. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. The proposed VSL language does not include ambiguous terms. The VSL is similar to the current approved VSL for BAL-005-0.2b Requirement R8.	Proposed VSLs do not expand on what is required in the requirement. Proposed VSLs are consistent with the requirement.	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VSLs for BAL-005-1 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 levels of noncompliance performance.	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-005-1 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.	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 an entity is non-compliant with the requirement.	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.

VSLs for BAL-005-1 Requirement R4:

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
R4.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSLs do not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the information was provided.	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.

VSLs for BAL-005-1 Requirement R5:

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
R5.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	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 an entity is non-compliant with the requirement.	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.

VSLs for BAL-005-1 Requirement R6:

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
R6.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	This requirement is new. As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on whether the entity implemented an Operating Process to identify and mitigate errors.	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.

VSLs for BAL-005-1 Requirement R7:

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
R7.	The NERC VSL Guidelines are satisfied. The requirement is binary and the performance measured does not meet the intent of the requirement.	As drafted, the proposed VSL does not lower the current level of compliance.	Proposed VSL is binary and therefore only has a severe VSL. 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. 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 2010-14.2.1 Balancing Authority Reliability-based Controls

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in FAC-001-3, Facility Interconnection Requirements. 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 FAC-001-3:
There are four requirements in FAC-001-3. All of the requirements were assigned a "Lower" VRF.

VRF for FAC-001-3, Requirement R1:

There were no changes made to requirement R1. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VRF for FAC-001-3, Requirement R3:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a “Lower” VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R3.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R3 which has an approved Lower 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 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 FAC-001-3, Requirement R4:

- FERC Guideline 2 — Consistency within a reliability standard exists. All of the requirements in FAC-001-3 are assigned a “Lower” VRF. This is also consistent with the current FERC approved VRF in FAC-001-2 Requirement R4.
- FERC Guideline 3 — Consistency among Reliability Standards exists. This requirement is similar in concept to the current enforceable FAC-001-2 standard Requirement R4 which has an approved Lower 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 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 FAC-001-3 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 FAC-001-3 Requirement R1:

There were no changes made to requirement R1. The current FERC approved VSLs are proposed to remain in effect.

VSLs for FAC-001-3 Requirement R2:

There were no changes made to requirement R2. The current FERC approved VRFs are proposed to remain in effect.

VSLs for FAC-001-3 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.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	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 number of parts the entity failed to address.	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.

VSLs for FAC-001-3 Requirement R4:

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
R4.	The NERC VSL Guidelines are satisfied by incorporating levels of noncompliance performance.	As drafted, the proposed VSLs do not lower the current level of compliance. The proposed VSLs are similar to the current FERC approved VSLs in FAC-001-2 Requirement R3.	Proposed VSL is binary and therefore only has a severe VSL. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the number of parts the entity failed to address.	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.

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Introduction:

Tie Line Bias[1] (TLB) control has been used as the preferred control method in North America for 75 years. In the early 1950's the term Area Control Error (ACE) was developed for the specific implementation of coordinated Tie Line Bias control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE[2] in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary; reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the Bulk Electric System.

The following definitions are included in the NERC Glossary:

Definition:
Actual Frequency F_A **5/11/2015**
The Interconnection frequency measured in Hertz (Hz).

Definition:
Actual Net Interchange NI_A **5/11/2015**
The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, with all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange.

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[1] Capitalized terms hold the same definition as in the NERC glossary throughout this document.

[2] The CPS1 measure was among the first of the results based measures developed by NERC. It defined not how to perform control, but instead defined the target control results that were to be achieved, and a method to measure whether or not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, Area Control Error (ACE) has been used to describe many terms involved in TLB Control. Within a BAA's Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions in order to smooth the control signals; or, there may be additional "feed-forward" terms added to ACE in anticipation of future changes (e.g. anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting to improve the quality of control for the specific characteristics of that particular BAA.

Some auditors have raised compliance issue related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in BAL-001. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Definition:

Automatic Time Error Correction **I_{ATEC}** **5/11/2015**

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 (PII) to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$\boldsymbol{I}_{\mathbf{ATEC}} = \frac{\boldsymbol{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/off\ peak}}}{(\mathbf{1-Y})*\mathbf{H}}$$ when operating in Automatic Time Error Correction mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$.

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

- $\mathbf{L_{max}}$ is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $\mathbf{L_{10}} = 1.65 * \mathcal{E}_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\mathcal{E}_{10}}$ 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, $\mathcal{E}_{10}$, is the same for every Balancing Authority Area within an Interconnection.
- **Y** = B_i / B_S.
- **H** = Number of hours used to payback primary Inadvertent Interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- $\mathbf{B_S}$ = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange ($\mathbf{PII_{hourly}}$) is $(1\text{-}Y) * (II_{actual} - B_i * \Delta TE/6)$
- $\mathbf{II_{actual}}$ 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: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- $\mathbf{TD_{adj}}$ 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.
- $\mathbf{TE_{offset}}$ is 0.000 or +0.020 or -0.020.
- $\mathbf{PII_{accum}}$ is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\boldsymbol{PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} = \boldsymbol{last\ period's\ PII}_{\boldsymbol{accum}}^{\boldsymbol{on/offpeak}} + \boldsymbol{PII}_{\boldsymbol{hourly}}$$

Definition:

Frequency Bias Setting **B** **4/1/2015**

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority Area's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Definition:

Interchange Meter Error $\mathbf{I_{ME}}$ **5/11/2015**

A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Definition:

Reporting ACE **RACE** **5/11/2015**

The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Definition:
Scheduled Frequency **F_S** **3/16/2007**
60.0 Hz, except during a manual Time Error Correction.

Definition:
Scheduled Net Interchange **NI_S** **5/11/2015**
The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Structure:

The effective use of Reporting ACE within a TLB control program should address the following components:

(I) Management Roles and Expectations
(II) Information Technology Roles
(III) System Operator Roles
(IV) Manual Source Data Entry
(V) Automatically Collected Source Data
(VI) Uses of Reporting ACE
(VII) Historic Data Management
(VIII) Special Conditions and Calculations

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the Tie Line Bias control program.

Each responsible entity should evaluate all of its uses for Reporting ACE in its operations and its reliability measurement. Reporting ACE is one of the most important single measurements available to indicate the current state of the Responsible Entity's contribution to interconnection reliability.[3] Reporting ACE is also used as an integral part of the measurements used in BAL-001 and BAL-002. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in BAL-003 and BAL-005.

I. Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Tie Line Bias control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

a. Set expectations for safety, reliability, and operational performance.

[3] When configured with a Frequency Bias Setting equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match its actual interchange, less the impact from its current Frequency Response offset, to its scheduled interchange.

b. Assure that a TLB control program exists for each responsible entity and is current.
c. Provide annual training on the TLB control program and its purpose and requirements.
d. Ensure the proper expectation of TLB control program performance.
e. Share insights across industry associations.

II. Information Technology (IT) Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE and source information are always current and correct.
c. Implement the TLB control program in Real-time.
d. Ensure that the EMS supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.
e. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.
f. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the following calculations and equations:

1) Actual Net Interchange[4] (NI_A):

All BAAs involved account for the power exchange and associated transmission losses as actual interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout all of their energy accounting processes.

i. Calculate for each scan.[5]
ii. Integrated hourly average calculated for each hour as an integration of the scan rate values.

[4] By definition "Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.
[5] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

2) Scheduled Net Interchange[6] (NI_S):
   i. Calculate for each scan.
   ii. Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

   Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout all of their energy accounting processes.

3) Frequency Error ($\Delta F = (F_A - F_S)$):
   i. Calculate for each scan.
   ii. Calculate clock-minute average from valid samples available within each clock-minute[7] where at least half of the scan-rate samples are valid.

4) Frequency Trigger Limit – Low (FTL_{Low})[8]:

   Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

5) Frequency Trigger Limit – High (FTL_{High})[9]:

   Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

6) Accumulated primary Inadvertent Interchange (PII): Calculated each hour for WECC BAAs only.

$$\boldsymbol{PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}}$$

7) Automatic Time Error Correction (IATEC): Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

   $\boldsymbol{I_{ATEC}} = \dfrac{\boldsymbol{PII_{accum}^{on/off\ peak}}}{\boldsymbol{(1-Y)*H}}$ when operating in ATEC mode.

   The absolute value of **I_{ATEC}** shall not exceed **L_{max}** .

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

[6] By definition "Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

[7] Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

[8] This variable could be entered manually as long as it is changed every time a manual time error correction is started or stopped. If manual time error correction is eliminated, it could become a constant and entered manually.

8) Reporting ACE:
   i. Calculate for each scan.
   ii. Calculated average for each clock-minute for BAAs using a fixed Frequency Bias Setting when at least half of the values are valid.[9]

9) Compliance Factor[10]:
   i. Calculate for each scan where both Reporting ACE and Frequency Error are valid.
   ii. Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[11]

10) Clock-hour compliance factor[8]:

    Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

11) Month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid clock-minute compliance factors in the month.

12) 12-month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

13) CPS1 compliance factor:

    Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the $Epsilon_1$ value for the Interconnection.

14) CPS1:
   i. Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.
   ii. Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.
   iii. Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2

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[9] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid.

[10] Used for CPS1.

[11] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid and the average clock-minute Frequency Error is valid.

and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

iv. Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

v. Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

15) Balancing Authority ACE Limit - Low ($BAAL_{Low}$):

i. Calculate the scan rate Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

16) Balancing Authority ACE Limit - High ($BAAL_{High}$):

i. Calculate the scan rate Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

17) Balancing Authority ACE Limit - Low Compliance:

i. Alarm $BAAL_{Low}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$.

ii. Indicate $BAAL_{Low}$ non-compliance for each period where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$ for more than 30-consecutive clock-minutes.

18) Balancing Authority ACE Limit - High Compliance:

i. Alarm $BAAL_{High}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$.

ii. Indicate $BAAL_{High}$ non-compliance for each period where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$ for more than 30 consecutive clock minutes.

g. Ensure that the EMS supports the retention of all historic data including data quality information required to be retained to support continuing operations and audit requirements.

h. Ensure that the EMS supports and manages the presentation of all information required to be available to the System Operator for real-time operations, operations staff for evaluation of operations, and auditors for compliance confirmation.

i. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.

III. System Operator and Operations Staff Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE information is always current and correct.
c. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.
d. Implement the TLB control program in Real-time.

IV. Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[12], by the Responsible Entity's Energy Management System (EMS), and may be partially based on source data manually entered into that system. The following source data may be entered:

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent Balancing Authority Areas may not be available from an automatic collection source, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent Balancing Authority Areas entering the manual data. If the actual flow estimates are the same for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

NI_S (Scheduled Net Interchange): The power transfer schedules, including the schedule ramps where applicable, are processed by the EMS. If scheduled flow estimates are equal and have opposite signs for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The Frequency Bias Setting, or minimum required value, for the Balancing Authority Area is specified by calculations performed as part of compliance with BAL-003-1 - Frequency Response and Frequency Bias Setting;

R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area 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

[12] BAL-005-1 Balancing Authority Control - R2. The Balancing Authority shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE.

(ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.[13]

10 is the factor (10 0.1Hz/Hz) that converts the Frequency Bias Setting units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor as specified in BAL-004-0.[14] It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all times.

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for **I_{ATEC}** set by each BA between 0.2*|B| and L_{10}, $0.2*|B| \leq L_{max} \leq L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is normally set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum Frequency Bias Settings for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the interconnection.

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[13] As a note of interest, the new procedures put forth with BAL-003-1 will result in the reduction of minimum Frequency Bias Setting values on the multiple BA interconnections to bring them closer to the natural measured Frequency Response of the interconnection. The rule requiring a minimum Frequency Bias Setting of 1% of peak load in the NERC Standards dates back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response which was 2% of peak load at that time. The 1% figure is now more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid.

[14] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

V. Automatically Collected Source Data

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds[15], by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the System Operators. This data quality information is presented to the System Operator to have situational awareness with respect to the quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as CPS1, BAAL, DCS, and frequency response obligation (FRM).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[16,17,18,19] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the System Operator to support situational awareness.[20] The EMS sums the individual flow values on all tie lines and pseudo ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry element is passed to the result of all calculations using that element.

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent Balancing Authority Area, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent Balancing Authority Area for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005[21] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

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[15] BAL-005-1 Balancing Authority Control – "R2. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[16] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS. See the attached document titled "Anti-aliasing Filtering."

[17] It is acceptable to collect tie-line flow data from RTUs that use report by exception as long as those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[18] The six-second scan rate not only assures that data collected is close to Real-time, it also limits the latency (time skew) associated with the data collection.

[19] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[20] Indications of suspect data are usually indicated with color changes and/or alarms.

[21] BAL-005 – Automatic Generation Control specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the Digital Frequency Transducer.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange. (Block schedules are not used for this calculation.)

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

VI. Uses of Reporting ACE

a. Reporting ACE is currently used to measure secondary frequency control within TLB control on all of the Interconnections.[22] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing Standards. The following standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

   i. BAL-001-1 – Real Power Balancing Control Performance and BAL-001-2 – Real Power Balancing Control Performance.

   ii. BAL-002-1 – Disturbance Control Performance and BAL-002-2 – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved).

   iii. BAL-005-0.2b – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved).

   iv. BAL-006-2 Inadvertent Interchange.

b. The industry may also consider the use of Reporting ACE in the future to evaluate the rules associated with transmission loading.

VII. Historic Data Management

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and "TLB control program".

VIII. Special Conditions and Calculations

IX. **I_{ME} (Interchange Meter Error):** BAL-005-1 R6 requires, "Each Balancing Authority Area that is within a multiple Balancing Authority Area interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE." Ideally, errors identified should be corrected immediately, but this is not always possible. The **I_{ME}** term, normally zero, can be used by the System Operator or operations staff to add a correction term in the Reporting ACE calculation correcting errors affecting the scan-rate accuracy of data, thus mitigating the error in the calculation of Reporting ACE until telemetry errors can be corrected.

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[22] On single BAA Interconnections, the ACE Equation reduces to a single term, **$-10B\ (F_A - F_S)$**, because there are no tie lines or schedules to include in the first term, **$(NI_A - NI_S)$**, and there is no **I_{ME}** term to correct for tie line or dynamic schedule measurement errors in the first term.

The calculation of the $\mathbf{I_{ME}}$ is the one of the results of this required Operating Process. It compensates for data or equipment errors affecting components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. The process used for including adjustments in the $\mathbf{I_{ME}}$ term should be based on good quality control methods.[23]

The goal associated with the use of the $\mathbf{I_{ME}}$ is to encourage the scan-rate values of actual and scheduled interchange between Adjacent Balancing Authorities to be equal in magnitude and have opposite signs.[24] Unfortunately, these values cannot be directly compared with each other because of differences between scan time and differences between scan-rates between BAAs. When initially configured, all BAs used “Digital to Analog” converters and “Analog to Digital” converters to transmit tie-line flows and accumulated MWh values from the common metering point required in the standards to the BA’s EMS. These “D to A” and “A to D” converters are subject to error and require frequent calibration, and although, many have been replaced by digital telemetry, they still exist and require oversight. Any difference between the scan-rate values agreed to by Adjacent BAAs that is not included in the error mitigation process will be passed to the interconnection for management and will not be included in the performance measures such as CPS1, BAAL and FRM.

Energy Management Systems are capable of integrating the scan-rate values used for the calculation of Reporting ACE and providing those integrated values for comparison to the accumulated megawatt-hour values for the same meters. If the integrated scan rate values are close to the accumulated megawatt-hour values, then one can conclude that the scan-rate values accurately represent the accumulated values. The final step in this process includes a comparison and agreement on the accumulated megawatt-hour values between the Adjacent BAAs sharing the measurement. If the differences between accumulated values between Adjacent BAAs is not included in this process, any adjustments to the accumulated values made by a BAA to achieve agreement with an adjacent BAA will be excluded from the analysis and will not be mitigated. This information used in conjunction with a similar analysis of the scan rate values for the same measurement by the Adjacent Balancing Authority Area including analysis of any differences between the accumulated values and the agreed to accumulated values. This total process provides reasonable assurance that the scan-rate tie line flows or the dynamic schedules used by Adjacent BAAs are consistent with one another confining control problems within the boundaries of the Adjacent BAAs.

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[23] Adjustments to the $\mathbf{I_{ME}}$ term should follow good quality control methods and exclude tampering as demonstrated by the Deming’s Funnel Experiment, http://blog.newsystemsthinking.com/w-edwards-deming-and-the-funnel-experiment/ .

[24] As long as the scan-rate tie line flows and scheduled flows match for Adjacent Balancing Authority Areas, any problems with the measurement of balancing on the interconnection will be confined to within the boundaries of those Adjacent Balancing Authority Areas. Any mismatch will pass the difference to the interconnection and will result in frequency control error that will to be excluded from performance measurement and managed by all BAAs through the frequency bias terms of their Reporting ACE.

These error correction adjustments can be used to correct errors in the **NI_A** or **NI_S**[25] terms for Reporting ACE and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the **I_{ME}** term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-1.

a. **Use of Source-Sink Pairs for Asynchronous DC Tie Lines to Another Interconnection:** One of the primary rules for insuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie lines, pseudo ties, interchange schedules and Dynamic Schedules to Adjacent Balancing Authority Areas and only Adjacent Balancing Authority Areas on the same Interconnection, and requiring the exclusion of all asynchronous DC tie lines and associated scheduled interchange with Balancing Authority Areas on a different Interconnection from Reporting ACE. Following this simple rule insures that all loads, losses and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie line bias control program. One terminal of an asynchronous DC tie line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie line will exclude the asynchronous tie line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

[25] Errors in the **NI_S** would only occur and only support correction in cases where there is a measurement error associated with a Dynamic Schedule.

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[*Capitalized words will have the same meaning as listed in the NERC Glossary of Terms and Rules of Procedures unless defined otherwise within this document.*]

INADVERTENT INTERCHANGE
Relationship to Reliability, Industry Practices, and Options for the Future

Introduction

The purpose of this document is to explain why a North American Electric Reliability Corporation (NERC) Reliability Standard is not required for Inadvertent Interchange (also referred to herein as Inadvertent) accounting and that Inadvertent accounting should be addressed through commercial means.

Included within this document are the typical practices that Balancing Authority Areas (BAA) within the NERC area currently follow, which allows for the development of commercial methods to address inadvertent balances. These practices provide a method for isolating and eliminating the source(s) of Inadvertent accounting errors.

Simple data errors (either value or sign) made in the acquisition of Actual Net Interchange or Scheduled Net Interchanges may become operating problems if they become a part of the Reporting ACE calculation. Regarding the deliberate creation or reduction of Inadvertent, this happens through implementation of bilateral or unilateral Inadvertent payback or a false Schedule offset to correct a perceived metering error. Also, Inadvertent is created or reduced because it is calculated using hourly Actual Net Interchange and Scheduled Net Interchanges without compensation for ramps. Finally, Inadvertent is inherently created because generation cannot physically follow the electrical demands of the system with absolute precision. Viewed from a total interconnected network (Interconnection) perspective, when the summation of all Balancing Authority Area Inadvertent within an Interconnection no longer sums to zero, there will exist a generation surplus or deficiency on the Interconnection. Ultimately this shows up in the form of aggregated scheduled frequency deviations, or Time Error.

Does Inadvertent Interchange Relate to Reliability?

Short-term or limited accumulations of Inadvertent Interchange do not cause reliability issues and are a part of normal interconnected operation in a multi-Balancing Authority Area Interconnection.

With the evolution of industry, technical advancements in measurements, and more visibility of the real-time operations, Inadvertent Interchange has little or no reliability impact. However, large and long-held primary Inadvertent Interchange accumulations do impact commercial relationships and their paybacks can create impacts to reliability if not conducted in an appropriate manner.

Causes of Inadvertent Interchange Accumulations

Some of the most common causes of Inadvertent Interchange are:

1) data recording errors;
2) metering errors;
3) scheduling errors;
4) ramping representation errors;
5) intentional control adjustments (temporary frequency support, smoothing algorithms, and ACE filter gain factors); and,
6) unintentional control errors (from both human action and Automatic Generation Control (AGC) errors);

Data Recording Errors

Simple data recording errors (incorrect value or sign) made while recording Actual Net Interchange or Scheduled Net Interchange can become operating reliability problems, depending upon the magnitude of the error, if they become a part of the Reporting ACE calculation. When viewed from the Interconnection perspective, if the sum of all Balancing Authority Areas' Inadvertent Interchange accumulations no longer sum to zero due to these data errors, frequency will be driven high or low, depending on the direction of the imbalance. If not resolved, imbalances due to data errors show up in the form of recurring Time Error. Other sources of error with Actual Net Interchange or Scheduled Net Interchange are identified in the following paragraphs.

Metering Errors

All Tie Lines between Adjacent Balancing Authority Areas should reflect the same coincident values at all times. Adjacent Balancing Authorities sharing a common tie are expected to use common metering with a synchronized freeze at hour-end. This is intended to assure that both Balancing Authorities capture the same value from the meter's register or accumulators. However, errors can occur due to the loss of telemetry by one or both Balancing Authority Areas or in the difference between an integrated analog value being used by one party and a megawatt-hour meter value being used by the other party. Another error may be created when two Adjacent Balancing Authority Areas use different scaling factors. These errors should be addressed through the requirements of the proposed BAL-005-1 and calculation of Reporting ACE, since it requires that hour-ending values be equal but opposite direction between Adjacent Balancing Authority Areas. It is important to note that, with respect to common metering, the requirement under currently-effective BAL-006-2 regarding a Balancing Authority's obligation to ensure that all of its Balancing Authority Area interconnection points are equipped with common megawatt hour meters has been moved to proposed BAL-005-1 at Requirements R1 and R8.

Scheduling Errors

All Interchange Schedules between Adjacent Balancing Authorities should reflect the same value with opposite direction. Errors can occur due to improper entry of data (time, amount, direction, duration, etc.) or improper updates in real-time. While these errors may occur, it is not acceptable for two Balancing Authorities to knowingly operate to dissimilar Schedules ("to agree to disagree"). These types of errors should be addressed through the requirements of the proposed BAL-005-1 and calculation of Reporting ACE.

Ramping Representation Errors - Accounting Anomaly

The practice of using block (contract) Scheduled Net Interchanges instead of integrated Scheduled Net Interchanges (the ramping effect) and subtracting the block values from integrated Actual Net Interchange creates a "built-in" false error. Longer duration ramps have the potential to produce larger errors. This is a false error because it gives the perception that an error occurred when, in fact, the Balancing Authority may have had perfect control and, yet, Inadvertent Interchange was created. These types of errors should be addressed through the requirements of the proposed BAL-005-1 and calculation of Reporting ACE.

Intentional Control Errors – Frequency Support [expected]

Frequency continually changes as system load or generation changes. Balancing Authority Areas have a responsibility to support frequency by acting in opposition to these changes. When measured frequency is different than the Scheduled Frequency (due to Demand changes or generation change) Balancing Authority Areas throughout an Interconnection adjust dispatch to arrest the frequency changes and support frequency until it is restored to its Scheduled value, in accordance with BAL-001, BAL-002, and BAL-003. During this period each Balancing Authority Area adjusts its resources to create more or less energy than is needed to serve its area Demand in order to support frequency, thus creating Inadvertent Interchange. In contrast to previous errors, intentional control errors are created by other standard requirements as opposed to being mitigated by them.

Unintentional Control Errors [unexpected]

If a Balancing Authority has insufficient regulating resources committed to follow its Demand variability and provide frequency support, Inadvertent Interchange may result. Poor control algorithms, generation outages, or generation deviation from Scheduled output could also cause Inadvertent Interchange to accumulate.

Further, unintentional control errors are inherently created with the most basic physical model of power generation, namely system inertia. A generating unit is unable to follow load with absolute precision due to the amount of energy that is required to change a generating units output and the instantaneous nature of load pickup that can occur. As load on the system changes, Balancing Authorities are varying their generation levels to meet this load, and a generator cannot follow a load with exact precision. The aggregation of these small differences in generation and load balance can create inadvertent energy on the system.

Finally, an incorrectly calibrated frequency meter will send a false indication to a Balancing Authority Area's AGC causing it to operate uncoordinated with other Balancing Authority Areas in the Interconnection. This will result in Inadvertent accumulations for the Balancing Authority Area with the erroneous frequency input and unwanted accumulations by other Balancing Authority Areas in the Interconnection. However, the proposed BAL-005-1 should limit the impacts of incorrectly calibrated frequency meters.

Since the BAL Standards all require the Balancing Authorities to calculate ACE in accordance with the definitions, and within these Standards, there are requirements to mitigate errors used in the calculation of ACE, the resulting Inadvertent should be caused by the generation physically not being able to follow the precise electrical demands of the system.

Inadvertent Interchange

Inadvertent is zero for an hour when the Actual Net Interchange is equal to the Scheduled Net Interchange for that hour. The goal of each Balancing Authority is to appropriately manage its Inadvertent accumulations. Accomplishing this goal requires that settlement policies within their Interconnection exist.

The retired NERC Policy 1F supported the short-term and long-term goals by stating: "Each balancing authority shall be active in preventing unintentional Inadvertent Interchange accumulations. Each Balancing Authority shall also be diligent in reducing accumulated Inadvertent balances in accordance with Operating Policies." This policy set no limits on the amount of Inadvertent that could be accumulated or when it must have been paid back. This policy was not a reliability policy, but was an accounting policy and should be resolved through commercial means.

Interchange Accounting

1. Accounting of Interchange. Accounting of energy between Balancing Authorities residing within the same Interconnection is both simple and complicated. In theory, Inadvertent Interchange is the difference between Actual Net Interchange and the Scheduled Net Interchange over a given period, usually an hour. Mathematically, it is the time integral of the deviation of a Balancing Authority's Actual Net Interchange from its Scheduled Net Interchange:

$$NI_I = NI_A - NI_S$$

Where,

NI_I is Inadvertent Interchange. In accordance with NERC convention, negative values of Inadvertent Interchange denote a condition of importing energy or under-generation and positive values denote exporting energy or over-generation.

NI_A is Actual Net Interchange. It is the algebraic sum of the hourly integrated energy on a Balancing Authority's Tie Lines including Pseudo-ties. Actual Net Interchange is positive for power leaving the system and negative for power entering it.

NI_S is Scheduled Net Interchange. It is defined as the mutually prearranged net energy on a Balancing Authority's Tie Lines including Dynamic Schedules or fixed Schedules for any jointly owned or contracted generation. The Scheduled Net Interchange is positive for power scheduled to be delivered from the Balancing Authority Area and negative for power Scheduled to be received into the Balancing Authority Area.

2. **Actual Net Interchange Energy Accounting**. Actual Net Interchange (metered interchange) between two Adjacent Balancing Authority Areas over a common Tie Line is accounted for at a specific point in the line. Furthermore, both Balancing Authorities shall agree on the amount of energy flow through this point, including any Pseudo-Tie flows that may exist between the two Balancing Authority Areas. Therefore, the sum of metered energy accounted by both Balancing Authority Areas over this Tie Line nets to zero. Since this is true for all Balancing Authority Areas within the same Interconnection, the algebraic sum of all metered energy within the same Interconnection is also zero.

3. **Scheduled Net Interchange Energy Accounting**. All Interchange Schedules shall have an agreed-upon Interchange Transaction size (megawatts), a start and end time, a beginning and ending ramp time and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction. Dynamic Schedules and fixed Schedules for jointly owned or contracted generation between Balancing Authority Areas should be agreed to on an hour-by-hour basis, and included in the Scheduled Net Interchange of both Balancing Authority Areas. The algebraic sum of Scheduled Net Interchange accounted by both Balancing Authority Areas must equal zero. Since every Interchange Schedule is agreed to by all involved delivering and receiving Balancing Authority Areas within an Interconnection, the algebraic sum of all Scheduled Net Interchange is also zero.

4. **Inadvertent Interchange Energy Accounting**. As stated previously, Inadvertent Interchange is the difference between Actual Net Interchange and Scheduled Net Interchanges over a given period. Since the algebraic sum of all Actual Net Interchange and the algebraic sum of all Scheduled Net Interchanges for any given period is zero within an Interconnection, the sum of all inadvertent interchange is also zero.

When Reporting ACE is properly implemented according to principles 2 and 3 included in the NERC definition, the above four conditions will result. This balancing of Inadvertent energy accounting allows effective payback methods to be implemented.

Inadvertent Interchange Energy Accounting Practices

The practices set forth in this section outline the methods required to reconcile energy accounting and inadvertent interchange balances.

For a Balancing Authority Area to properly monitor and account for Inadvertent Interchange, all Balancing Authority Areas must follow the same methodology within that Interconnection.

1. **Accounting Procedures**

1.1. **On-Peak and Off-Peak Accounting Periods**. Each Balancing Authority is obligated to maintain its Inadvertent Interchange accounting within two periods, namely, On-Peak and Off-Peak.

1.2. **Interchange Schedules**. All hourly Schedules and Schedule changes shall be agreed upon between the Balancing Authority Areas involved prior to implementation in regard to common magnitude, rate of change, starting time, and ending time.

1.3. **Dynamic Schedules**. Dynamic Schedules integrated on an hourly basis shall be agreed upon by the Balancing Authority Areas involved subsequent to the hour, but in such a manner as not to impact Inadvertent accounts. This is accomplished by assuring that the hourly actual and scheduled Interchange quantities agree between all delivering and receiving parties.

1.4. **Daily Accounting**. Each Balancing Authority shall agree with its Adjacent Balancing Authority Area as to the hourly values of actual Interchange (megawatt hour) scheduled interchange (megawatt hour) for On-Peak and Off-Peak periods.

1.5. **Monthly Accounting**. Having agreed to the On-Peak and Off-Peak period hourly values on a daily basis, Balancing Authorities should expect the summation of accumulated values for the month to balance to zero for each Interconnection.

1.6. **Adjustments for Error**. Adjustments shall be made each month to correct for differences between hourly megawatt hour meter totals and the hourly integrated totals derived from register readings at the Tie Line meters.

1.6.1 **Differences.** Adjacent Balancing Authorities shall agree upon the difference determined above and assign this correction to the proper On-Peak and Off-Peak period and in equal quantities in the opposite directions.

1.6.2 **Adjustments.** Adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner as 1.6.1.

2. **NAESB Standard WEQ-007 Business Practices Requirements:**

2.1. Inadvertent Interchange payback. Each Balancing Authority shall be diligent in reducing Inadvertent Interchange accumulations. Balancing Authorities shall payback Inadvertent Interchange accumulations by one of the following methods:

2.1.1. Energy “in-kind” payback. Inadvertent Interchange accumulated during “On-Peak” hours shall only be paid back during “On-Peak” hours. Inadvertent Interchange accumulated during “Off-Peak” hours shall only be paid back during “Off-Peak” hours.

2.1.1.1. Bilateral payback. Inadvertent Interchange accumulations may be paid back via an Interchange Schedule with another Balancing Authority.

2.1.1.1.1. Opposite balances. The Source Balancing Authority Area and Sink Balancing Authority Area must have Inadvertent Interchange accumulations in the opposite direction.

2.1.1.1.2. Payback terms. The terms of the Inadvertent Interchange payback shall be agreed upon by all involved Balancing Authorities and Transmission Service Providers.

2.1.1.2. Unilateral payback. Inadvertent Interchange accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a nonzero ACE ensures that the unilateral payback is accounted for in the CPS1 calculations. The unilateral payback control offset is limited to Balancing Authority Areas' L_{10} limit and shall not burden the Interconnection.

2.1.2. Other payback methods. Upon agreement by all Regional entities within an Interconnection, other methods of Inadvertent Interchange payback may be utilized. The Western Interconnection established a regional reliability standard BAL-004-WECC-02 – Automatic Time Error Correction in which Primary Inadvertent Interchange payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.

2.1.3. Implementation of the following Reporting ACE equation by all Regions entities within an Interconnection would result in automatic Inadvertent payback for that interconnection independent of Time Error Correction as implemented on the Western Interconnection.

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

Where:

I_{AIP} (Automatic Inadvertent Payback) is the addition of a component to the Reporting ACE equation that modifies the control point for the purpose of continuously paying back Inadvertent Interchange to correct accumulated Inadvertent accounts without correcting for Time Error.

$$I_{AIP} = \frac{II_{accum}^{on/off\ peak}}{H}$$ when operating in Automatic Inadvertent Payback mode.

The absolute value of I_{AIP} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for I_{AIP} set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.

- 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.
- **H** = Number of hours used to payback Inadvertent Interchange energy.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- $\mathbf{B_S}$ = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Inadvertent Interchange is $\mathbf{II_{actual}}$ is the hourly Inadvertent Interchange for the last hour.
- $\mathbf{II_{accum}}$ is the Balancing Authority Area's accumulated $\mathbf{II_{actual}}$ in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\mathrm{II}_{accum}^{on/offpeak} = \textit{last period's}\ \mathrm{II}_{accum}^{on/offpeak} + \mathrm{II}_{actual}$$

Implementation of Automatic Inadvertent Payback as shown above would also require a modification to the Reporting ACE definition in the NERC Glossary to allow for its implementation in the Reporting ACE equation.

3. Inadvertent Interchange over Direct Current Tie Lines between Separately Synchronous Interconnections

For the purpose of NERC inadvertent interchange calculations, there shall be no contribution to a Balancing Authority's Reporting ACE or Inadvertent accumulation due to a direct current tie connecting Adjacent Balancing Authorities operating in separate Interconnections.

4. Summary of Accounting Rules

4.1. **Summation of Interchange Schedules.** The summation of all Interchange Schedules within an Interconnection shall total zero for any period of time.

4.2. **Summation of Actual Net Interchange.** The summation of all Actual Net Interchange within an Interconnection shall total zero for any period of time.

4.3. **Summation of inadvertent interchange for Interconnection.** The summation of all Inadvertent Interchange within an Interconnection shall total zero for any period of time.

5. Accounting Examples

Daily, total Net Actual Interchange for each hour accumulated during the On-Peak and Off-Peak periods. Do the same with the Scheduled Net Interchanges. By period, subtract the totaled Scheduled Net Interchange from the totaled Actual Net Interchange. This will yield On-Peak and Off-Peak Inadvertent accumulations for the day. The addition of these two accumulations is the Balancing Authority's Inadvertent Interchange accumulation for the day. All Balancing Authorities must keep an accurate, continuous record of their current balances of On-Peak, Off-Peak, and (net) Inadvertent for the day, month, and accumulative to date, to meet accounting requirements

Need for a Reliability Standard

It is recognized that Tie Line Bias operation results in the creation of Inadvertent Interchange. The need for action required for reliable system operation is reflected in the requirements in the proposed BAL-005-1. Actions to resolve potential reliability problems associated with Inadvertent is addressed in the BAL-005 requirements. Inadvertent accumulation is an equity issue that cannot be solved with a reliability requirement.

NERC Reliability Standards are based on principles that define the foundation of reliability for the North American Bulk Electric System. Each Standard enables or supports one or more of these principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Electric System.

Even though FERC Order 693 directs the ERO to develop modifications to BAL-006 to add requirements to address certain issues associated with Inadvertent, Inadvertent accumulation does not cause the Interconnection to be unreliable. However, if a Balancing Authority Area's Inadvertent accumulation is extremely large, it may drive most of the other accumulations held by other Balancing Authority Areas in the Interconnection to become uncomfortably large in the opposite direction. This may drive unilateral paybacks resulting in a topological shift in transmission loadings to the point of becoming a reliability problem. Normally, there is no reliability issue associated with Inadvertent.

The proposed BAL-005-1 requirements, along with the requirements of BAL-001, BAL-002, and BAL-003, establish the reliability requirements for Balancing Authorities to ensure that a Balancing Authority does not excessively depend on other Balancing Authorities in the Interconnection to meet their Demand or Interchange obligations.

The NERC Resources Subcommittee and Inadvertent Interchange Working Group, which serve at the pleasure of the NERC Operating Committee, will continue to monitor Inadvertent Interchange, in conjunction with the aforementioned suite of balancing Reliability Standards, to ensure that Inadvertent accumulations do not result in adverse impacts on reliability.

FERC Order No. 693 was issued prior to other changes in the industry, such as the modified BAL-001-2 and the new BAL-003-1, along with the work on BAL-002-2 and the proposed BAL-005-1. All of these changes are designed to ensure that Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection to meet their Demand obligations. Some of the changes are designed to allow for Inadvertent while supporting Interconnection frequency and reducing the need to move generation in one direction or the other (over-generating or under-generating). To allow for these changes, while enhancing reliability, the drafting team is proposing a commercial method to resolve Inadvertent while accommodating the requirements of Order 693. In light of other requirements and proposed requirements under the BAL Reliability Standards, the drafting team is recommending a commercial requirement rather than a reliability requirement. The Commission has already established such a procedure when handling imbalance charges within the Open Access Tariffs.

Commercial Requirement

If all the requirements within proposed BAL-005-1 are met continuously by the Balancing Authority Areas, reliability requirements are met and thus Inadvertent Interchange accumulations are a commercial issue.

A commercial requirement is necessary to:

1) Establish a tracking mechanism for Inadvertent Interchange accumulations (currently provided through CERTS Inadvertent application), and
2) Encourage settlements within a reasonable time period.

These reasons are explained in the following paragraphs.

Quality Control

Inadvertent data requires the ability to measure the accuracy and effectiveness of meters, scheduling systems, and energy management systems, as indicated in the requirements of the proposed BAL-005-1. As such, it provides a check and balance for the measurement systems.

Data Accuracy

Inadvertent data requires that all Balancing Authority Areas within an Interconnection have accurate data for timely management of Inadvertent accumulations and a process for reducing accumulated Inadvertent balances.

Diagnostic Tool to Validate Performance

Inadvertent Interchange is a source of independent data for diagnostic purposes as recommended by the U.S.-Canada Power System Outage Task Force. NERC Reliability Standards BAL-001. BAL-002, and BAL-003 are used to evaluate Balancing Authority reliability performance.

The proposed Reliability Standard BAL-005-1 contains requirements for a system operator to examine real-time system inputs to determine if a metering problem exists, a Schedule is incorrectly entered, or the frequency indication is erroneous.

From an Interconnection viewpoint, Inadvertent accumulations over a given time period (e.g., several months) can occur without making an Interconnection unreliable. An Interconnection may have operated within the prescribed safe frequency range; however, one Balancing Authority Area may have been over-generating, while another was under-generating. Thus the Interconnection was reliable and balanced. The resulting accumulated Inadvertent becomes an equity issue.

Tracking Mechanism for Accumulations

Since Inadvertent always sums to zero for an Interconnection, every megawatt hour of positive Inadvertent held by one Balancing authority area is balanced with a megawatt hour of negative Inadvertent held by another. Therefore, a Balancing Authority Area holding an amount of Inadvertent accumulation forces other Balancing Authority Areas to hold a collective amount of Inadvertent accumulation in the opposite direction.

Balancing Authority Areas should track their accumulations of Inadvertent Interchange to assure equity among the Balancing Authority Areas within the Interconnection is maintained. Monthly and accumulated Inadvertent Interchange balances are presently tracked and reported via a CERTS Inadvertent Interchange Reporting Application. This reporting process should be maintained to insure that accurate Inadvertent balances are recorded and available for analysis.

Reasonable Time Limit for Settling Accumulations
While the retired NERC Policy 1F encourages Balancing Authorities to "be diligent in reducing accumulated Inadvertent balances", it does not indicate the time period that these reductions must occur. Is it acceptable to hold accumulated Inadvertent balances for years?

Inadvertent Interchange Payback Schemes

An Inadvertent Interchange accumulation means that demands in the Balancing Authority Area with a negative accumulation of Inadvertent interchange are in part supplied off-schedule by generators in the other Balancing Authority Areas. Symmetrically, generators in an area with a positive accumulation of Inadvertent interchange supply Demands in some other areas off-schedule. Effectively, the Inadvertent Interchange accumulation means systematic over-generation or under-generation in the corresponding Balancing Authority Area. This economic imbalance can be settled either through the financial mechanisms, or unilateral or bilateral Inadvertent interchange payback schemes discussed previously. However, any commercial mechanism must be an agreed to and coordinated scheme and applied equally to everyone within the Interconnection. If any Balancing Authority does something different than what has been agreed for the Interconnection, then a reliability problem may arise.

Options

Unilateral Payback Schemes
In the unilateral payback scheme, a Balancing Authority Area unilaterally and intentionally over-generates or under-generates over a certain time interval, in accordance with an agreed upon process or NAESB standard, to pay the corresponding negative or positive Inadvertent Interchange accumulation back to the Interconnection. This scheme can be automated as it is done in the Western Interconnection through the Reliability Standard BAL-004-WECC-02.

Bilateral Payback Schemes
In the bilateral scheme, two Balancing Authority areas, one with a positive and one with a corresponding negative Inadvertent Interchange accumulation, agree upon the time and the size of a scheduled inadvertent Interchange payback. Unlike the unilateral Inadvertent Interchange

payback, this scheme must be balanced and not impact the Interconnection active power balance or Interconnection frequency.

Automatic Payback Schemes

In an Automatic Payback scheme as described in 2.1.3 of this document, all Balancing Authorities in an Interconnection agree to "payback" the same proportion of their accumulated Inadvertent in each hour. Since the accumulated Inadvertent on and off peak accounts are balanced, the resulting Reporting ACE adjustments would also be balanced and have no reliability effect on the Interconnection active power balance or Interconnection frequency.

The payback procedures must be conducted separately for the on-peak and off-peak hours.

Financial Settlement

With a financial settlement mechanism, a price must be established for each Interconnection. One could equate a financial settlement to the current imbalance charges within entities Open Access Transmission Tariffs (OATT). The OATTS provisions settle under and over-generation for the specific Balancing Authority Areas through a specific price while maintaining the reliability of the Interconnection. Inadvertent is an imbalance for the Interconnection. A commercial price could be established for the Interconnection, where the over-generating Balancing Authority area would receive a payment while the under-generating Balancing Authority Area would pay.

The commercial price for each Interconnection could be established through a FERC process or through a NAESB process. However, the commercial rules and procedures should be clear and defined.

The financial arrangements could be administered through a third party established by FERC for the Interconnection. Rules would need to be established on various issues, such as timing, the amount of inadvertent a Balancing Authority area could accumulate over a given period, and others. However, one could use the current OATT imbalance charge process as a guideline to establish such a financial settlement for Inadvertent.

Unofficial Survey Form

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls: Inadvertent Interchange BAL-006

DO NOT use this form for submitting survey responses. Use the electronic form to submit survey responses on Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls: Inadvertent Interchange (BAL-006). Responses must be submitted by **8 p.m. Eastern, Friday, September 25, 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

This Project 2010-14.2.1 Phase 2 Balancing Authority Reliability-based Controls standard drafting team (SDT) is soliciting comments from the industry concerning the disposition of BAL-006. The Independent Expert Review Report, Periodic Review Team, and (during the SAR comment phase) industry indicated that majority of currently-effective Reliability Standard BAL-006-2 as written is an energy accounting standard and not a Reliability Standard.

The Federal Energy Regulatory Commission (“Commission”) recommended the development of a metric to bind the magnitude of inadvertent accumulations, as those accumulations may be indicative of a Balancing Authority excessively leaning on the resources of others in its Interconnection. The SDT consensus was that an Inadvertent Interchange accumulation value alone cannot yield useful information concerning whether a Balancing Authority is operating reliably. The SDT has proposed revisions to BAL-005, and, the SDT believes that with these revisions and the other suite of BAL Standards, the Reliability Standards address reliable operation of Balancing Authorities.

Thus, with the evolution of the industry, technical advancements in measurements, and more visibility of the real-time operations, Inadvertent Interchange has little or no impact on reliability. However, large and long-held Inadvertent Interchange accumulations do impact commercial relationships, and their paybacks can create impacts to reliability if they are not conducted appropriate manner. This is discussed in a white paper being posted contemporaneously with this survey.

Questions

1. Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]

 Modify and maintain BAL-006 as a Reliability Standard.

 Maintain BAL-006 (with no changes) as a Reliability Standard.

 Eliminate BAL-006 as a Reliability Standard.

 Comments:

2. If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?

 Yes:

 No:

 Comments:

3. If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?

 Yes:

 No:

 Comments:

4. If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.

 Comments:

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1 When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

5. If you have any other comments or reliability concerns, please provide them in the space below.

   Comments:

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** BAL-006-XX

3. **Purpose:**

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

4. **Applicability:**

   4.1. Balancing Authorities.

5. **Effective Date:** First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

Note that as the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this proposed redline.

B. Requirements

R1. Each Balancing Authority shall agree with its Adjacent Balancing Authorities by the end of the next business day on: (*Violation Risk Factor: Lower*)

R1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact.

R4.1. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Balancing Authority’s Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver (Project 2009-18).	Revision
2	November 5, 2009	Approved by the Board of Trustees	
2	January 6, 2011	Approved by FERC	

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** BAL-006-XX

3. **Purpose:**

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

4. **Applicability:**

4.1. Balancing Authorities.

5. **Effective Date:** First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

Note that as the revisions proposed for BAL-006 focus on the minimum requirements for Adjacent Balancing Authorities to agree upon the hourly MW amounts of scheduled and actual Interchange between them, which reinforces that errors in coordination or process will be identified, the PRT recommends that the SDT revise the Purpose statement to be consistent with the Requirements as further developed under the SAR posted with this proposed redline.

B. Requirements

~~**R1.** Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)~~

~~**R2.** Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)~~

~~**R3.** Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)~~

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

~~**R5.**~~**R1.** Each Balancing Authority~~, by the end of the next business day,~~ shall agree with its Adjacent Balancing Authorities by the end of the next business day ~~to~~on: (*Violation Risk Factor: Lower*)

~~**R5.1.**~~**R1.1.** The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

~~**R5.2.**~~**R1.2.** The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

~~**R6.**~~**R2.** Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

~~**R7.**~~**R3.** ~~A~~Each Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact.

~~**R7.1.**~~**R4.1.** The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Balancing Authority’s Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
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2	November 5, 2009	Approved by the Board of Trustees	
2	January 6, 2011	Approved by FERC	

Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls: Inadvertent Interchange BAL-006

Survey Being Conducted through September 25, 2015

Now Available

The Project 2010-14.2.1 Phase 2.1 Balancing Authority Reliability-based Controls standard drafting team is soliciting comments from the industry concerning the disposition of BAL-006-2. The Independent Expert Review Report, Periodic Review Team, and industry (during the SAR comment period) indicated that majority of BAL-006-2 as written is an energy accounting standard and not a reliability standard. However, it was unclear what exactly the industry desires to accommodate the need for energy accounting. With the evolution of industry, technical advancements in measurements, and more visibility of the real-time operations, Inadvertent Interchange has little or no reliability impact. However, large and long-held Inadvertent Interchange accumulations do impact commercial relationships and their paybacks can create impacts to reliability if not conducted in an appropriate manner. Responses must be submitted by **8 p.m. Eastern, Friday, September 25, 2015**.

Use the electronic form to submit survey responses. If you experience any difficulties in using the electronic form, 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).

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Survey Report

Survey Details

Name 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls: Inadvertent Interchange | BAL-006 Survey

Description

Start Date 9/16/2015

End Date 9/25/2015

Associated Ballots

Survey Questions

1. Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]

[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

Modify and maintain BAL-006 as a Reliability Standard.

Maintain BAL-006 (with no changes) as a Reliability Standard.

Eliminate BAL-006 as a Reliability Standard.

2. If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?

Yes

No

3. If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?

Yes

No

4. If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.

5. If you have any other comments or reliability concerns, please provide them in the space below.

Responses By Question

1. Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]

[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Maintain BAL-006 (with no changes) as a Reliability Standard.

Answer Comment:

The current effective version of BAL-006 requires metering at all BAA interconnection points (R3). The proposed version of BAL-006 removes the requirement for metering. Although requirement for metering may be addressed in changes to other BAL or FAC Standards, until that occurs BAL-006 should remain as written.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Information

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Voter Information

Voter	Segment
Terry BIlke	2
Entity	**Region(s)**
Midcontinent ISO, Inc.	

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Our preference is to eliminate this standard with one caveat. We believe BAL-006 should be converted to a guide and placed in the NERC Operating Manual. The tasks done under this standard are useful housekeeping tasks that support validation of balancing data.

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Southern agrees with the PRT that BAL-006 is an energy accounting standard and not a Reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6

Entity	Region(s)
Duke Energy	FRCC,SERC,RFC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Duke Energy supports the elimination of BAL-006 as a Reliability Standard, based on the belief that the requirements, with the exception of certain provisions of R4 incorporated into the proposed BAL-005-1, are business in nature and are not needed to support the reliable operation of the Bulk Power System.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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
Wayne Van Liere	1,3,5,6
Entity	**Region(s)**
PPL - Louisville Gas and Electric Co.	SERC

Selected Answer: Modify and maintain BAL-006 as a Reliability Standard.

Answer Comment:

In order to maintain enforcement capability, BAL-006 should remain a Reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6

Entity	Region(s)
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

FE supports PJM comments on this issue.

While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Group Information

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Voter Information

Voter	Segment
Shawn Abrams	1
Entity	**Region(s)**
Santee Cooper	

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment:

We believe the SDT has provided adequate analysis on supporting rationale to eliminate BAL-006. Inadvertent Interchange is addressed through other existing reliability and commercial requirements. However, we believe the SDT could have provided better documentation to support its conclusions by identifying how each requirement are addressed individually. We believe the SDT should develop a “mapping document” that accompanies its white paper to better substantiate its conclusions.

Document Name:

Likes: 0

Dislikes: 0

2. If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: No

Answer Comment:

Comments: The purpose listed in the draft of BAL-006 has not been changed from the previously approved standard and does not appear directly related to the drafted requirements.

The elimination of the currently effective BAL-006 R4 in the draft removes a requirement that no other standard addresses.

See also answer to question 1.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

NA as AZPS does not support retaining as a NERC standard.

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Information

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Voter Information

Voter

Terry BIlke

Segment

2

Entity

Midcontinent ISO, Inc.

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

We suggest BAL-006 be retired.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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
Wayne Van Liere	1,3,5,6
Entity	**Region(s)**
PPL - Louisville Gas and Electric Co.	SERC

Selected Answer: Yes

Answer Comment:

To address FERC's recommendation for a metric to bind the magnitude of a BA's inadvertent accumulation, LG&E and KU suggest a multiplier of L10. For example, for a BA with an L10 of 100, a multiplier of 250 would permit an accumulation of up to 25,000 MWHs. The limit on the accumulation needs to reflect the relative size of the BA.

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

BPA supports eliminating NERC BAL-006-2 as a reliability standard based on the NERC SDT (Standard Drafting Team) white paper provided for consideration. As the white paper suggests, the current requirements in NERC BAL-006-2 of a reliability nature should be addressed through the requirements of the proposed BAL-005-1.

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Group Information

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Voter Information

Voter	Segment
Shawn Abrams	1
Entity	**Region(s)**
Santee Cooper	

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: No

Answer Comment:

We believe the SDT has provided adequate analysis on supporting reasons why BAL-006 should be eliminated. We also believe that Paragraph 81 criteria could be applied to eliminate the remaining requirements. Based on Paragraph 81 Criteria for Administrative and Reporting, we feel the SDT has provided sufficient technical basis to substantiate that these requirements do “not support reliability and is needlessly burdensome.” We also feel that in the instance when Adjacent BAs do not agree upon interchange quantities, the need to report such disputes to Regional Entities aligns with the definition of the Paragraph 81 Reporting Criterion. This specific criterion states that “these are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.”

Document Name:

Likes: 0

Dislikes: 0

3. If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment:

NERC could accomplish the data collection under rules of procedure as opposed to a reliability standard.

See answers to question 1 and 2 for elements of the current BAL-006 that would need to be addressed in reliability standards.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment:

Reconciliation of inadvertent

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Information

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Voter Information

Voter	Segment
Terry BIlke	2
Entity	**Region(s)**
Midcontinent ISO, Inc.	

Selected Answer: No

Answer Comment:

We do not support turning this over to NAESB or FERC. NAESB business practices ultimately become part of a transmission provider's tariff. Not all transmission providers are Balancing Authorities. Additionally, not all Balancing Authorities are FERC jurisdictional. Rather than creating gaps and make the data unverifiable, our preference is that BAL-006 be converted to a guide or procedure and placed in the NERC Operating Manual.

The guidelines or procedure could be drafted and maintained in the operating manual by taking the existing verbiage and replace "shall" with "will", "needs to", or "should".

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6

Entity	Region(s)
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: No

Answer Comment:

Southern would prefer this be handled with agreements between the entities. However, if a standard is required, we suggest it be within NAESB and not a NERC Reliability Standard.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Duke Energy recommends moving the responsibilities present in R1-R3, as well as R4.1 of BAL-006 to the NAESB standards. NAESB already handles certain aspects of Interchange, and Inadvertent accounting is considered to be a business practice or commercial in nature. We believe the requirements listed above fit that description. We have excluded R4 from moving to NAESB, as we believe it would be covered by the proposed BAL-005-1 upon approval.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Document Name:

Likes: 0

Dislikes: 0

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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
Wayne Van Liere	1,3,5,6
Entity	**Region(s)**
PPL - Louisville Gas and Electric Co.	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer: Yes

Answer Comment:

FE supports PJM comments on this issue.

PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Group Information

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Voter Information

Voter	**Segment**
Shawn Abrams	1
Entity	**Region(s)**
Santee Cooper	

Selected Answer: Yes

Answer Comment:

We support maintaining the current reporting requirements through the CERTS Inadvertent Interchange Reporting Application.

Document Name:

Likes: 0

Dislikes: 0

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Yes

Answer Comment:

Refer it to NAESB and incorporate all of the BAL-006 requirements in a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer: Yes

Answer Comment:

We agree that commercial alternative arrangements, such as a NAESB Business Practices, are a better fit for Inadvertent Interchange.

Document Name:

Likes: 0

Dislikes: 0

4. If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment: Support transferring to NAESB

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Information

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Voter Information

Voter	Segment
Terry BIlke	2
Entity	**Region(s)**
Midcontinent ISO, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment: NA

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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
Wayne Van Liere	1,3,5,6
Entity	**Region(s)**
PPL - Louisville Gas and Electric Co.	SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

FE supports PJM comments on this issue.

This question is not applicable as PJM feels that Inadvertent Interchange requirements should be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Group Information

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Voter Information

Voter	Segment
Shawn Abrams	1
Entity	**Region(s)**
Santee Cooper	

Selected Answer:

Answer Comment:

n/a

Document Name:

Likes: 0

Dislikes: 0

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment: We suggest that the SDT eliminate BAL-006.

Document Name:

Likes: 0

Dislikes: 0

5. If you have any other comments or reliability concerns, please provide them in the space below.

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:

Answer Comment:

Requirements in BAL-006 as proposed for deletion are of value in a Standard, see answers to Question 1 and 2.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Information

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Voter Information

Voter	Segment
Terry BIlke	2
Entity	**Region(s)**
Midcontinent ISO, Inc.	

Selected Answer:

Answer Comment:

If our suggestion is not supported, we would suggest balloting the posted standard and make the VRFs and VSLs reflect the fact that the requirements in this standard have little or no impact on reliability.

Document Name:

Likes: 0

Dislikes: 0

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Voter Information

Voter	Segment
Marsha Morgan	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment: NA

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter	Segment
Colby Bellville	1,3,5,6
Entity	**Region(s)**
Duke Energy	FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Duke Energy's support for the elimination of BAL-006 as a Reliability Standard, and the aforementioned requirements transition to the NAESB standards, predicated on the assumption that the Real-time reliability requirements of BAL-006 will be covered in one way (approval of proposed BAL-005-1) or another (incorporated into an existing BAL standard).

Given that the proposed BAL-005-1 will include a requirement covering the current BAL-006 R4, Duke Energy recommends that the BAL-005-1 implementation plan factor in the possible hand over of BAL-006 responsibilities from NERC to NAESB so that there isn't the possibility of BAL-005-1 being effective at the same time that BAL-006 is still in place with a duplicate requirement.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment: As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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
Wayne Van Liere	1,3,5,6
Entity	**Region(s)**
PPL - Louisville Gas and Electric Co.	SERC

Selected Answer:

Answer Comment:

LG&E and KU are not opposed to handling inadvertent via a NAESB standard or business practice; the concern is enforceability. A NAESB standard or business practice for inadvertent would lack enforcement "teeth." Thus LG&E and KU question whether a NAESB standard can as effectivelty achieve the desired result.

LG&E and KU are not in favor of financial or FERC established processes for settlement of accumulated inadvertent accounts.

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Information

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Voter Information

Voter	Segment
Richard Hoag	1,3,4,5,6
Entity	**Region(s)**
FirstEnergy - FirstEnergy Corporation	RFC

Selected Answer:

Answer Comment:

FE supports PJM comments on this issue.

As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Document Name:

Likes: 0

Dislikes: 0

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Group Information

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Voter Information

Voter	Segment
Shawn Abrams	1
Entity	**Region(s)**
Santee Cooper	

Selected Answer:

Answer Comment:

n/a

Document Name:

Likes: 0

Dislikes: 0

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Brian Van Gheem	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

We question the practice of NERC posting this survey with the expectation of a nine-day, weekend included, turnaround for the possible elimination of a reliability standard. This survey was posted during a week with NERC Technical Committee meetings, which likely impacted the availability of many industry and NERC subject matter experts to provide comments. We hope this condensed commenting period was an oversight and a one-time occurrence.

Thank you for the opportunity to comment.

Document Name:

Likes: 0

Dislikes: 0

Consideration of Comments

Project Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-006 Survey

Comment Period Start Date: 9/16/2015

Comment Period End Date: 9/25/2015

There were 14 responses, including comments from approximately 43 different people from approximately 33 different companies representing 6 of the 10 Industry Segments as shown on the following pages.

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.

Summary Response

The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. During the development of the recommendation, the PRT also considered stakeholder recommendations for candidate Paragraph 81 requirements from Phase 1 of Paragraph 81, and applied the Paragraph 81 criteria to all of the requirements. The team also considered the Independent Expert Review Panel recommendations on the standard.

After an extensive review, the BARC 2 PRT concluded that Reliability Standard BAL-006-2 was not a reliability standard, however, certain provision were necessary for the operations of the Interconnection.

The Balancing Authority Reliability-based Controls 2.1 Standard Drafting Team (BARC 2.1 SDT) reviewed the findings of the BARC 2 Primary Review Team. A survey was posted for comment September 16-25, 2015 to gain a better perspective as to any concerns the industry may have if BAL-006-2 was retired and replaced with a non-reliability process, such as a guideline or a business practice. The survey responses indicated support for retirement of BAL-006-2 as a NERC Reliability Standard. Upon further review the BARC 2.1 SDT determined that BAL-006-2 does not support the reliability of the BES. BAL-006-2 is an accounting business requirement and not a reliability standard. Therefore BAL-006-2 should be retired.

The BARC 2.1 SDT's recommendation for retirement of BAL-006-0 is contingent on simultaneous establishment of a NERC Operating Committee Guideline for the ongoing required accounting of inadvertent interchange. The BARC 2.1 SDT is coordinating the development of such a guideline with the NERC Operating Committee.

Questions

1. **Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]**
2. **If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?**
3. **If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?**
4. **If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.**
5. **If you have any other comments or reliability concerns, please provide them in the space below.**

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

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[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]

[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Maintain BAL-006 (with no changes) as a Reliability Standard.

Answer Comment: The current effective version of BAL-006 requires metering at all BAA interconnection points (R3). The proposed version of BAL-006 removes the requirement for metering. Although requirement for metering may be addressed in changes to other BAL or FAC Standards, until that occurs BAL-006 should remain as written.

Response:

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: Our preference is to eliminate this standard with one caveat. We believe BAL-006 should be converted to a guide and placed in the NERC Operating Manual. The tasks done under this standard are useful housekeeping tasks that support validation of balancing data.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: Southern agrees with the PRT that BAL-006 is an energy accounting standard and not a Reliability Standard.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: **Duke Energy supports the elimination of BAL-006 as a Reliability Standard, based on the belief that the requirements, with the exception of certain provisions of R4 incorporated into the proposed BAL-005-1, are business in nature and are not needed to support the reliable operation of the Bulk Power System.**

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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

Selected Answer: Modify and maintain BAL-006 as a Reliability Standard.

Answer Comment: In order to maintain enforcement capability, BAL-006 should remain a Reliability Standard.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5

Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: FE supports PJM comments on this issue.

While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Response:

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: We believe the SDT has provided adequate analysis on supporting rationale to eliminate BAL-006. Inadvertent Interchange is addressed through other existing reliability and commercial requirements. However, we believe the SDT could have provided better documentation to support its conclusions by identifying how each requirement are addressed individually. We believe the SDT should develop a "mapping document" that accompanies its white paper to better substantiate its conclusions.

Response:

2. If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: No

Answer Comment: Comments: The purpose listed in the draft of BAL-006 has not been changed from the previously approved standard and does not appear directly related to the drafted requirements.

The elimination of the currently effective BAL-006 R4 in the draft removes a requirement that no other standard addresses.

See also answer to question 1.

Response:

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment: NA as AZPS does not support retaining as a NERC standard.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: We suggest BAL-006 be retired.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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

Selected Answer: Yes

Answer Comment: To address FERC's recommendation for a metric to bind the magnitude of a BA's inadvertent accumulation, LG&E and KU suggest a multiplier of L10. For example, for a BA with an L10 of 100, a multiplier of 250 would permit an accumulation of up to 25,000 MWHs. The limit on the accumulation needs to reflect the relative size of the BA.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: BPA supports eliminating NERC BAL-006-2 as a reliability standard based on the NERC SDT (Standard Drafting Team) white paper provided for consideration. As the white paper suggests, the current requirements in NERC BAL-006-2 of a reliability nature should be addressed through the requirements of the proposed BAL-005-1.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments

Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: No

Answer Comment: We believe the SDT has provided adequate analysis on supporting reasons why BAL-006 should be eliminated. We also believe that Paragraph 81 criteria could be applied to eliminate the remaining requirements. Based on Paragraph 81 Criteria for Administrative and Reporting, we feel the SDT has provided sufficient technical basis to substantiate that these requirements do "not support reliability and is needlessly burdensome." We also feel that in the instance when Adjacent BAs do not agree upon interchange quantities, the need to report such disputes to Regional Entities aligns with the definition of the Paragraph 81 Reporting Criterion. This specific criterion states that "these are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact."

Response:

3. If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment: NERC could accomplish the data collection under rules of procedure as opposed to a reliability standard.

See answers to question 1 and 2 for elements of the current BAL-006 that would need to be addressed in reliability standards.

Response:

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment: Reconciliation of inadvertent

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Selected Answer: No

Answer Comment: We do not support turning this over to NAESB or FERC. NAESB business practices ultimately become part of a transmission provider's tariff. Not all transmission providers are Balancing Authorities. Additionally, not all Balancing Authorities are FERC jurisdictional. Rather than creating gaps and make the data unverifiable, our preference is that BAL-006 be converted to a guide or procedure and placed in the NERC Operating

Manual.

The guidelines or procedure could be drafted and maintained in the operating manual by taking the existing verbiage and replace “shall” with “will”, “needs to”, or “should”.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: Southern would prefer this be handled with agreements between the entities. However, if a standard is required, we suggest it be within NAESB and not a NERC Reliability Standard.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy recommends moving the responsibilities present in R1-R3, as well as R4.1 of BAL-006 to the NAESB standards. NAESB already handles certain aspects of Interchange, and Inadvertent accounting is considered to be a business practice or commercial in nature. We believe the requirements listed above fit that description. We have excluded R4 from moving to NAESB, as we believe it would be covered by the proposed BAL-005-1 upon approval.**

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment: PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Answer Comment: FE supports PJM comments on this issue.

PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Response:

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Yes

Answer Comment: We support maintaining the current reporting requirements through the CERTS Inadvertent Interchange Reporting Application.

Response:

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Yes

Answer Comment: Refer it to NAESB and incorporate all of the BAL-006 requirements in a NAESB standard.

Response:

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: Yes

Answer Comment: We agree that commercial alternative arrangements, such as a NAESB Business Practices, are a better fit for Inadvertent Interchange.

Response:

4. If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment: Support transferring to NAESB

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment: NA

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment: FE supports PJM comments on this issue.

This question is not applicable as PJM feels that Inadvertent Interchange requirements should be moved to a NAESB standard.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Answer Comment: n/a

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Answer Comment: We suggest that the SDT eliminate BAL-006.

Response:

5. If you have any other comments or reliability concerns, please provide them in the space below.

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Answer Comment: Requirements in BAL-006 as proposed for deletion are of value in a Standard, see answers to Question 1 and 2.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Answer Comment: If our suggestion is not supported, we would suggest balloting the posted standard and make the VRFs and VSLs reflect the fact that the requirements in this standard have little or no impact on reliability.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment: NA

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment:

Duke Energy's support for the elimination of BAL-006 as a Reliability Standard, and the aforementioned requirements transition to the NAESB standards, predicated on the assumption that the Real-time reliability requirements of BAL-006 will be covered in one way (approval of proposed BAL-005-1) or another (incorporated into an existing BAL standard).

Given that the proposed BAL-005-1 will include a requirement covering the current BAL-006 R4, Duke Energy recommends that the BAL-005-1 implementation plan factor in the possible hand over of BAL-006 responsibilities from NERC to NAESB so that there isn't the possibility of BAL-005-1 being effective at the same time that BAL-006 is still in place with a duplicate requirement.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:

As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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:

LG&E and KU are not opposed to handling inadvertent via a NAESB standard or business practice; the concern is enforceability. A NAESB standard or business practice for inadvertent would lack enforcement "teeth." Thus LG&E and KU question whether a NAESB standard can as effectivelty achieve the desired result.

LG&E and KU are not in favor of financial or FERC established processes for settlement of accumulated inadvertent accounts.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4

Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment: FE supports PJM comments on this issue.

As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Answer Comment: n/a

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Answer Comment: We question the practice of NERC posting this survey with the expectation of a nine-day, weekend included, turnaround for the possible elimination of a reliability standard. This survey was posted during a week with NERC Technical Committee meetings, which likely impacted the availability of many industry and NERC subject matter experts to provide comments. We hope this condensed commenting period was an oversight and a one-time occurrence.

Thank you for the opportunity to comment.

Response:

End of report

Consideration of Comments

Project Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-006 Survey

Comment Period Start Date: 9/16/2015

Comment Period End Date: 9/25/2015

There were 14 responses, including comments from approximately 43 different people from approximately 33 different companies representing 6 of the 10 Industry Segments as shown on the following pages.

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.

Summary Response

The NERC Standards Committee appointed eleven industry subject matter experts to serve on the BARC 2 periodic review team (BARC 2 PRT) in the fall of 2013. The BARC 2 PRT used background information on the standards and the questions set forth in the Periodic Review Template developed by NERC and approved by the Standards Committee, along with associated worksheets and reference documents, to determine whether BAL-006-2 should be: (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. During the development of the recommendation, the PRT also considered stakeholder recommendations for candidate Paragraph 81 requirements from Phase 1 of Paragraph 81, and applied the Paragraph 81 criteria to all of the requirements. The team also considered the Independent Expert Review Panel recommendations on the standard.

After an extensive review, the BARC 2 PRT concluded that Reliability Standard BAL-006-2 was not a reliability standard, however, certain provision were necessary for the operations of the Interconnection.

The Balancing Authority Reliability-based Controls 2.1 Standard Drafting Team (BARC 2.1 SDT) reviewed the findings of the BARC 2 Primary Review Team. A survey was posted for comment September 16-25, 2015 to gain a better perspective as to any concerns the industry may have if BAL-006-2 was retired and replaced with a non-reliability process, such as a guideline or a business practice. The survey responses indicated support for retirement of BAL-006-2 as a NERC Reliability Standard. Upon further review the BARC 2.1 SDT determined that BAL-006-2 does not support the reliability of the BES. BAL-006-2 is an accounting business requirement and not a reliability standard. Therefore BAL-006-2 should be retired.

The BARC 2.1 SDT's recommendation for retirement of BAL-006-0 is contingent on simultaneous establishment of a NERC Operating Committee Guideline for the ongoing required accounting of inadvertent interchange. The BARC 2.1 SDT is coordinating the development of such a guideline with the NERC Operating Committee.

Questions

1. **Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]**
2. **If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?**
3. **If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?**
4. **If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.**
5. **If you have any other comments or reliability concerns, please provide them in the space below.**

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

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[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. Based on comments related to the SAR, the Independent Expert Review Report, and the Periodic Review Team' recommendations, the industry agrees that BAL-006 is an energy accounting standard and not a Reliability Standard, however, it is unclear what the industry supports as a replacement. The SDT has developed a white paper for the industry to consider. Based on the concepts within the white paper, do you support maintaining Reliability Standard BAL-006?[1]

[1] When responding to this survey and providing comments, please keep in mind that draft proposed Reliability Standard BAL-006-3 has been posted under 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls, in connection with draft proposed Reliability Standards BAL-005-1 and FAC-001-3. Proposed Reliability Standard BAL-005-1, at Requirements R1 and R8, would include the obligations currently under Requirement R3 of Reliability Standard BAL-006-2.

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Maintain BAL-006 (with no changes) as a Reliability Standard.

Answer Comment: The current effective version of BAL-006 requires metering at all BAA interconnection points (R3). The proposed version of BAL-006 removes the requirement for metering. Although requirement for metering may be addressed in changes to other BAL or FAC Standards, until that occurs BAL-006 should remain as written.

Response:

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: Our preference is to eliminate this standard with one caveat. We believe BAL-006 should be converted to a guide and placed in the NERC Operating Manual. The tasks done under this standard are useful housekeeping tasks that support validation of balancing data.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: Southern agrees with the PRT that BAL-006 is an energy accounting standard and not a Reliability Standard.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: **Duke Energy supports the elimination of BAL-006 as a Reliability Standard, based on the belief that the requirements, with the exception of certain provisions of R4 incorporated into the proposed BAL-005-1, are business in nature and are not needed to support the reliable operation of the Bulk Power System.**

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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

Selected Answer: Modify and maintain BAL-006 as a Reliability Standard.

Answer Comment: In order to maintain enforcement capability, BAL-006 should remain a Reliability Standard.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5

Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: FE supports PJM comments on this issue.

While PJM agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

Response:

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: Eliminate BAL-006 as a Reliability Standard.

Answer Comment: We believe the SDT has provided adequate analysis on supporting rationale to eliminate BAL-006. Inadvertent Interchange is addressed through other existing reliability and commercial requirements. However, we believe the SDT could have provided better documentation to support its conclusions by identifying how each requirement are addressed individually. We believe the SDT should develop a "mapping document" that accompanies its white paper to better substantiate its conclusions.

Response:

2. If you support maintaining BAL-006 as a Reliability Standard, are you in favor of the PRT recommendation as noted in the attached draft Reliability Standard BAL-006? If not, then what aspects of BAL-006 should be retained in a standard?

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer:	No
Answer Comment:	Comments: The purpose listed in the draft of BAL-006 has not been changed from the previously approved standard and does not appear directly related to the drafted requirements. The elimination of the currently effective BAL-006 R4 in the draft removes a requirement that no other standard addresses. See also answer to question 1.
Response:	

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment:	NA as AZPS does not support retaining as a NERC standard.
Response:	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: We suggest BAL-006 be retired.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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

Selected Answer: Yes

Answer Comment: To address FERC's recommendation for a metric to bind the magnitude of a BA's inadvertent accumulation, LG&E and KU suggest a multiplier of L10. For example, for a BA with an L10 of 100, a multiplier of 250 would permit an accumulation of up to 25,000 MWHs. The limit on the accumulation needs to reflect the relative size of the BA.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment: BPA supports eliminating NERC BAL-006-2 as a reliability standard based on the NERC SDT (Standard Drafting Team) white paper provided for consideration. As the white paper suggests, the current requirements in NERC BAL-006-2 of a reliability nature should be addressed through the requirements of the proposed BAL-005-1.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments

Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: No

Answer Comment: We believe the SDT has provided adequate analysis on supporting reasons why BAL-006 should be eliminated. We also believe that Paragraph 81 criteria could be applied to eliminate the remaining requirements. Based on Paragraph 81 Criteria for Administrative and Reporting, we feel the SDT has provided sufficient technical basis to substantiate that these requirements do "not support reliability and is needlessly burdensome." We also feel that in the instance when Adjacent BAs do not agree upon interchange quantities, the need to report such disputes to Regional Entities aligns with the definition of the Paragraph 81 Reporting Criterion. This specific criterion states that "these are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact."

Response:

3. If you support eliminating BAL-006 as a Reliability Standard, are you in favor of the SDT recommendation that these requirements be included in a commercial alternative arrangement, such as a NAESB standard or a process established by FERC? What aspects of BAL-006 should be retained in an alternative arrangement?

Laurel Brandt - Tennessee Valley Authority - 1,3,5,6 - SERC

Selected Answer: Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment: NERC could accomplish the data collection under rules of procedure as opposed to a reliability standard.

See answers to question 1 and 2 for elements of the current BAL-006 that would need to be addressed in reliability standards.

Response:

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Selected Answer: Yes

Answer Comment: Reconciliation of inadvertent

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Selected Answer: No

Answer Comment: We do not support turning this over to NAESB or FERC. NAESB business practices ultimately become part of a transmission provider's tariff. Not all transmission providers are Balancing Authorities. Additionally, not all Balancing Authorities are FERC jurisdictional. Rather than creating gaps and make the data unverifiable, our preference is that BAL-006 be converted to a guide or procedure and placed in the NERC Operating

Manual.

The guidelines or procedure could be drafted and maintained in the operating manual by taking the existing verbiage and replace “shall” with “will”, “needs to”, or “should”.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: Southern would prefer this be handled with agreements between the entities. However, if a standard is required, we suggest it be within NAESB and not a NERC Reliability Standard.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy recommends moving the responsibilities present in R1-R3, as well as R4.1 of BAL-006 to the NAESB standards. NAESB already handles certain aspects of Interchange, and Inadvertent accounting is considered to be a business practice or commercial in nature. We believe the requirements listed above fit that description. We have excluded R4 from moving to NAESB, as we believe it would be covered by the proposed BAL-005-1 upon approval.**

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment: PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Selected Answer: Yes

Answer Comment: FE supports PJM comments on this issue.

PJM believes the requirements in BAL-006 should be moved to a NAESB standard. In order for Inadvertent Interchange to be calculated appropriately the standard should include requirements similar to what the PRT has suggested for BAL-006. However PJM also believes that Adjacent Balancing Authorities should operate to a Net Interchange Schedule as this is important to avoid many potential dispute resolutions.

Response:

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Selected Answer: Yes

Answer Comment: We support maintaining the current reporting requirements through the CERTS Inadvertent Interchange Reporting Application.

Response:

Adam Padgett - TECO - Tampa Electric Co. - 1,3,5,6 - FRCC

Selected Answer: Yes

Answer Comment: Refer it to NAESB and incorporate all of the BAL-006 requirements in a NAESB standard.

Response:

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Michael Brytowski	Great River Energy	MRO	1,3,5,6

Selected Answer: Yes

Answer Comment: We agree that commercial alternative arrangements, such as a NAESB Business Practices, are a better fit for Inadvertent Interchange.

Response:

4. If neither maintaining nor eliminating BAL-006 is preferred, please describe your suggestion for the disposition of this standard.

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment: Support transferring to NAESB

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment: NA

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4
Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment: FE supports PJM comments on this issue.

This question is not applicable as PJM feels that Inadvertent Interchange requirements should be moved to a NAESB standard.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Answer Comment: n/a

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Answer Comment: We suggest that the SDT eliminate BAL-006.

Response:

5. If you have any other comments or reliability concerns, please provide them in the space below.

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Answer Comment: Requirements in BAL-006 as proposed for deletion are of value in a Standard, see answers to Question 1 and 2.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Group Name: IRC-SRC

Group Member Name	Entity	Region	Segments
Christina Bigelow	ERCOT	TRE	2
Kathleen Goodman	ISONE	NPCC	2
Ben Li	IESO	NPCC	2
Terry Bilke	MISO	RFC	2
Greg Campoli	NYISO	NPCC	2
Mark Holman	PJM	RFC	2
Charles Yeung	SPP	SPP	2

Answer Comment: If our suggestion is not supported, we would suggest balloting the posted standard and make the VRFs and VSLs reflect the fact that the requirements in this standard have little or no impact on reliability.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment: NA

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment:

Duke Energy's support for the elimination of BAL-006 as a Reliability Standard, and the aforementioned requirements transition to the NAESB standards, predicated on the assumption that the Real-time reliability requirements of BAL-006 will be covered in one way (approval of proposed BAL-005-1) or another (incorporated into an existing BAL standard).

Given that the proposed BAL-005-1 will include a requirement covering the current BAL-006 R4, Duke Energy recommends that the BAL-005-1 implementation plan factor in the possible hand over of BAL-006 responsibilities from NERC to NAESB so that there isn't the possibility of BAL-005-1 being effective at the same time that BAL-006 is still in place with a duplicate requirement.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:

As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Response:

Wayne Van Liere - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC

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:

LG&E and KU are not opposed to handling inadvertent via a NAESB standard or business practice; the concern is enforceability. A NAESB standard or business practice for inadvertent would lack enforcement "teeth." Thus LG&E and KU question whether a NAESB standard can as effectivelty achieve the desired result.

LG&E and KU are not in favor of financial or FERC established processes for settlement of accumulated inadvertent accounts.

Response:

Richard Hoag - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6 - RFC

Group Name: FE RBB

Group Member Name	Entity	Region	Segments
William Smith	FirstenergyCorp	RFC	1
Cindy Stewart	FirstEnergy Corp.	RFC	3
Doug Hohlbaugh	Ohio Edison	RFC	4

Robert Loy	FirstEnergy Solutions	RFC	5
Richard Hoag	FirstenergyCorp	RFC	NA - Not Applicable
Ann Ivanc	FirstEnergy Solutions	FRCC	6

Answer Comment: FE supports PJM comments on this issue.

As part of Project 2010-14.2.1 Phase 2 it was suggested that BAL-006-2 Requirement R3 be moved into BAL-005-3. While PJM agrees it is important to calculate MWh values for Inadvertent Interchange, PJM suggests this be moved to a NAESB standard.

Response:

Shawn Abrams - Santee Cooper - 1 -

Group Name: Santee Cooper

Group Member Name	Entity	Region	Segments
Shawn Abrams	Santee Cooper	SERC	1
James Poston	Santee Cooper	SERC	3
Michael Brown	Santee Cooper	SERC	6

Answer Comment: n/a

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6

Answer Comment:

We question the practice of NERC posting this survey with the expectation of a nine-day, weekend included, turnaround for the possible elimination of a reliability standard. This survey was posted during a week with NERC Technical Committee meetings, which likely impacted the availability of many industry and NERC subject matter experts to provide comments. We hope this condensed commenting period was an oversight and a one-time occurrence.

Thank you for the opportunity to comment.

Response:

End of report

Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Formal Comment Period Open through January 11, 2016

Now Available

A formal comment period for **BAL-005-1 – Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange** is open through **8 p.m. Eastern, Monday, January 11, 201.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. 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.

If you are having difficulty accessing the Standards Balloting & Commenting System 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

An additional ballot for the three standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for FAC-001-3 will be conducted **December 31, 2015 through January 11, 2016.**

Standards Development Process

For more information on the Standards Development Process, please 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
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comments Received Report

Project Name:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-2 & FAC-001-3
Comment Period Start Date:	11/10/2015
Comment Period End Date:	1/11/2016
Associated Ballots:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 Non-binding Poll IN 1 NB 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-006-2 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 IN 1 ST

There were 43 sets of responses, including comments from approximately 117 different people from approximately 84 companies representing 8 of the 10 the Industry Segments as shown in the table on the following pages.

Questions

1. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below.

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RFC	ISO Standards Review Committee	Charles Yeung	PJM Interconnection, L.L.C.	2	SPP
					Ben Li	PJM Interconnection, L.L.C.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RFC
					Kathleen Goodman	PJM Interconnection, L.L.C.	2	NPCC
					Greg Campoli	PJM Interconnection, L.L.C.	2	NPCC
					Ali Miremadi	PJM Interconnection, L.L.C.	2	WECC
					Terry Bilke	PJM Interconnection, L.L.C.	2	RFC
					Liz Axson	PJM Interconnection, L.L.C.	2	TRE
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	ACES Power Marketing	1	RFC
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Ellen Watkins	ACES Power Marketing	1	SPP
					Michael Brytowski	ACES Power Marketing	1,3,5,6	MRO
					John Shaver	ACES Power Marketing	4,5	WECC
					John Shaver	ACES Power Marketing	1	WECC
					Shari Heino	ACES Power Marketing	1,5	TRE
					Kevin Lyons	ACES Power Marketing	1	MRO

Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	Exelon	1	RFC
					John Bee	Exelon	3	RFC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RFC,SERC	Duke Energy	Doug Hils	Duke Energy	1	RFC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RFC
Lower Colorado River Authority	Dixie Wells	5		LCRA Compliance	Michael Shaw	Lower Colorado River Authority	6	TRE
					Teresa Cantwell	Lower Colorado River Authority	1	TRE
					Dixie Wells	Lower Colorado River Authority	5	TRE
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Kelly Dash	Kelly Dash		NPCC	Con Edison	Kelly Dash	Kelly Dash	1,3,5,6	NPCC
					Edward Bedder	Kelly Dash	NA - Not Applicable	NPCC
Dominion - Dominion Resources, Inc.	Louis Slade	6		Dominion	Randi Heise	Dominion - Dominion Resources, Inc.	5,6	NPCC

					Connie Lowe	Dominion - Dominion Resources, Inc.	1,3,5,6	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	5,6	RFC
					Chip Humphrey	Dominion - Dominion Resources, Inc.	5	SERC
					Nancy Ashberry	Dominion - Dominion Resources, Inc.	5	RFC
					Larry Nash	Dominion - Dominion Resources, Inc.	1,3	SERC
					Candace L Marshall	Dominion - Dominion Resources, Inc.	1,3	SERC
					Larry W Bateman	Dominion - Dominion Resources, Inc.	1,3	SERC
					Jeffrey N Bailey	Dominion - Dominion Resources, Inc.	5	SERC
					Russell Deane	Dominion - Dominion Resources, Inc.	5	NPCC
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company - Southern Company Services, Inc.	1	SERC
					John Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
					R Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William Shultz	Southern Company - Southern Company Services, Inc.	5	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no UI O&R	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power Coordinating Council	1	NPCC
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
					Brian Robinson	Northeast Power Coordinating Council	5	NPCC

					Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
					Alan Adamson	Northeast Power Coordinating Council	7	NPCC
					Kathleen M. Goodman	Northeast Power Coordinating Council	2	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michael Jones	Northeast Power Coordinating Council	3	NPCC
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
					Connie Lowe	Northeast Power Coordinating Council	4	NPCC
					Michael Forte	Northeast Power Coordinating Council	1	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
					Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC

Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP
					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP
					Kevin Giles	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP

1. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Modifying the definition of Balancing Authority would misalign the term with the definition found in the NERC Rules of Procedure. SRP recommends retaining the current definition of Balancing Authority.

The proposed definition of AGC combines defined terms to create the phrase “Balancing Authority Area Demand” ERC recommends rephrasing the definition to avoid using one defined term to modify another. An alternative might be “Demand within a Balancing Authority Area”.

Primary Inadvertent Interchange is not a NERC defined term. It is a defined WECC term, SRP recommends adding Primary Inadvertent Interchange to the terms used continent wide. as the revised ATEC definition will be effective continent wide.

SRP recommends removing or defining terms capitalized but not defined in the NERC Glossary of Terms such as Control Area and Balancing Area. Capitalizing terms that are not defined creates confusion even when used in the rationale areas.

Likes 0	
Dislikes 0	

Response

Theresa Rakowsky - Puget Sound Energy, Inc. - 1

Answer	No
Document Name	

Comment

The definition of AGC is fine, but in the process of combining the need for common sources regarding MW and MWh values into the proposed R7, the association between AGC, ACE, MW, and MWh quantities is less clear. The user now has to combine the definitions for AGC, Reporting ACE, and R7 to get an equivalent picture compared to the original requirement. Maybe some references or revised wording in R7 would help clarify the expectations.

Likes 0	
Dislikes 0	

Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy suggests a modification to the proposed definition of Automatic Generation Control (AGC), which we feel would enhance clarity and maintains the assumed intent of the drafting team. We recommend the following:

Automatic Generation Control (AGC): A process designed and used to automatically adjust a Balancing Authority Area's Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

We feel that the above definition adds clarity, and with the addition of the term automatically in the definition, more adequately describes the function that AGC provides.

Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	No
Document Name	
Comment	

HQT believes that Requirement 7 should apply specifically to tie lines, pseudo-ties and dynamic schedules that included in the ACE equation. Even though having the same scan-rate measure and having a time synchronized common source is a good practice, Tie-lines that are not included in the ACE equation that are not equipped with such will not affect adversely the control of a balancing authority. HQT proposes to modify R7 as below:

7. Each Balancing Authority shall ensure that each Tie Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority **that is included in the ACE equation** is equipped with: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt values, metered - mitigation of errors.

Likes 0	
Dislikes 0	
Response	
Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	

Answer	No
Document Name	

Comment

These comments are submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") LG&E/KU are registered in the SERC region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Yes

No X

Comments: LG&E/KU recommend the AGC definition be modified to add flexibility as follows:

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Area's Demand, Interchange, or resources, as applicable, to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

"Demand" is defined in the NERC Glossary as the rate at which energy is used by the customer. As written, the AGC definition could be interpreted to mean a BA is required to utilize Demand controls to adjust ACE. A BA should not be expected to use Demand controls to adjust ACE because the real-time nature of ACE and some current forms of Demand controls are not necessarily compatible. Additionally, the SDT's proposed definition does not mention Interchange which is a component of ACE and can be used to adjust ACE. Because Interchange has not typically been understood to be included in the term "resources," LG&E/KU recommend "Interchange" be expressly included in the definition of AGC. If the SDT does not accept the above recommendation, should it be the industry's understanding that the term "resources" includes Interchange?

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE recommends that the SDT consider the impact of changing the definition of Automatic Generation Control (AGC) on other NERC Glossary definitions prior to implementing such a change in this project. Although the SDT's stated goal of converting the AGC definition from a prescriptive "how to" requirement to an arguably more flexible, performance-based approach is laudable, Texas RE notes that AGC is used in other NERC Glossary definitions and, as currently defined, represents a commonly understood term in the industry. For example, the term AGC is used in the following defined terms: Anti-Aliasing Filter, Overlap Regulation Service, and proposed Remedial Action Scheme. Accordingly, modifying the AGC definition in one context without considering the consequences of such a change for other defined terms could introduce unnecessary uncertainty and confusion, as well as lead to unintended consequences. In light of the interlocking usage of AGC, Texas RE recommends that the SDT either retain the existing AGC definition or, at a minimum, consider the impact of changing the AGC definition as part of this project prior to making any changes.

If the SDT does move forward with the proposed changes to the AGC definition, Texas RE recommends revising the proposed definition slightly to correct what appears to be a typographical error. Specifically, Texas RE believes the phrase "that of" should be struck so that the proposed AGC definition reads: "A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE *in a* Balancing Authority Area within the bounds required by applicable NERC Reliability Standards."

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA disagrees with the modified definition of AGC; AGC is equipment or a system, not a process. Also, BPA suggests that the clause "...in that of a BAA..." could be simplified to "in a BAA."

Regarding the modified definition of Pseudo-Tie, BPA requests clarification of what constitutes an "alternate control process."

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern suggests the below change to the definition of AGC:

A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	Yes
Document Name	

Comment

The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be:

"A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards."

Please check and revise as appropriate.

Likes 0	
Dislikes 0	

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We would suggest to the drafting team to develop a rationale box for the modification of the Pseudo Tie definition as they did for the AGC definition. We feel this would help provide clarity on why the drafting team made the modifications to this term's definition and how this change will have an impact on the reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be: **"A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards."** **Please check and revise as appropriate.**	
Likes 0	

Dislikes 0	
Response	
Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelly Dash - Kelly Dash, Group Name Con Edison	
Answer	

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Appelbaum - United Illuminating Co. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC	
Answer	
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

R1: BPA requests definition of “design scan rate” as identified in the R1. Scan rate is not a defined term in the NERC Glossary. It is unclear to what the SDT means by design scan rate and why the word “design” was added in this second draft.

R6: BPA still has concerns as to how R6 would be met. This requirement seems subjective and open-ended; it would be difficult for an auditor to apply a consistent metric or method to validate compliance. BPA proposes the following: “Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to ensure the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. The process must accomplish the following:
a. Compare MWh values from common source meters to integrated scan rate values
b. Xxx
c. Xxx

In **R7.1** BPA requests “information....for the scan rate values used in the calculation of Reporting ACE” be defined. BPA is unsure how to address the dynamic schedule portion of this requirement.

In **R7.2**, many dynamic schedules do not have MWH meters; the MWH value is simply the integrated scan rate data for the dynamic schedule. BPA proposes 7.2 be modified to read:
7.2 for all Tie-Lines and metered Psuedo-Ties and metered Dynamic Schedules, a time-synchronized common source to determine hourly megawatt-hour values agreed upon to aid in the identification and mitigation of errors.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We continue to have concerns with Requirement R4 and the approach taken in the wording of this requirement. We agree with the SDT that bad data quality will lead to an inaccurate ACE calculation. However, we feel the SDT should move away from concerns over data quality and instead focus on Reporting ACE calculation capabilities, as it is used by System Operators as a primary metric in making critical operating decisions.

(2) The term “operator” in Requirement R4 is too broad and the SDT should replace it with “System Operator.” When we previously identified this as a concern, the SDT’s response was that “By using the term operator, the BA will assure the information is provided to the correct personnel.” Balancing Authorities are already required to identify such personnel as System Operators in PER-003-1 R3. The SDT should use the System Operator glossary term to align with other reliability requirements and to avoid confusion.

(3) We suggest that Requirement R5 be removed because there is an equally efficient and suitable manner of achieving the reliability result through the NERC Event Analysis (EA) Process. The EA Process, category 1h, requires entities to report when there is a loss of monitoring or control at a Control Center, and could include Reporting ACE calculation capabilities. Hence, this requirement would then be unnecessary.

(4) The SDT assumes that all tie lines between Balancing Authorities use time-synchronized meters. This may not always be true. We recommend the removal of the term “time synchronized” in Requirement R7, Part 7.2 and allow Balancing Authorities to continue to operate to a common source when conducting their end-of-hour checks with their Adjacent Balancing Authorities. We also recommend the expansion of the VSLs for Requirement R7 where failure to meet one part would be High, and failure to meet both would be Severe.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

We have a concern pertaining to Requirement R3 parts 3.1 and 3.2. Our group would suggest that the drafting team provide clarity on what are the intents for this particular Requirement and its parts. At this particular time, we are interpreting that the frequency source has to be within 1mHz accuracy for 99.95% of the year.

Likes 0	
Dislikes 0	

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

In R6 the SDT is using a new term called “scan rate data” which is not a defined term. This term is rather ambiguous. The phrase “affecting the accuracy of data” is clear enough. Or possibly say the accuracy of data used in calculating ACE. In 7.1 the SDT uses a term called “scan rate values”. The scan rate is how fast we collect the data, it is not the type of data used here. All SCADA data has a scan rate, this could really be referring to almost anything.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Requirement R1: Scan Rate

In reading Requirement R1 and M1, it is unclear whether or not there is a requirement to utilize a scan rate. R1 indicates “The Balancing Authority shall use a design scan rate…” This almost looks like it should read “The Balancing Authority shall use a scan rate” OR “The Balancing Authority shall design a scan rate”. Texas RE recommends there be a requirement to both design and utilize a scan rate as it increases the integrity of data during events as indicated by the rationale.

Requirement R4: System Operator

As previously submitted for the initial ballot, Texas RE recommends the SDT use the term “System Operator” in R4. The rational states “System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculations are incorrect, the operator should be made aware through visual display. When an operator questions the validity of the data, actions are delayed and the probability of adverse events occurring can increase.” The definition of System Operator is “An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.” The response provide by the SDT to this issue was “The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.” A System Operator needs to be aware of any data issues to make the correct decisions. A BA can provide the information to any other personnel it so desires but the System Operator must, at a minimum, have access to the Reporting ACE information. As written, and interpreted by the SDT, there could be possible gaps in providing the individuals whose responsibility it is to monitor and control that electric system in real time correct information. There may not be consistency within Balancing Authorities as to who the “operator” is in this requirement. Texas RE suggests the verbiage “System Operator and other personnel (as determined by the BA)” to provide clarity. As is, if a System Operator does not have the information the Balancing Authority will be compliant but may hinder reliability by delaying actions and increasing the probability of adverse events occurring. The non-definitive term “operator” will inherently inject non-uniformity in determining compliance. Each entity will have a different interpretation of what “operator” means which will appear as an inconsistency in the Regional Entity review. If an “operator” who is not a System Operator is making and acting on decisions that control the electric system in real time, is that not a concern of the SDT?

Requirement R6: Singe Balancing Authority Interconnection

Texas RE noticed R6 does not address a single Balancing Authority Interconnection. Texas RE recommends there be a requirement for an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in calculating Reporting ACE even in single Balancing Authority Interconnections.

Reporting ACE

Texas RE recommends the standard language explicitly state how DC ties should be handled rather than indicating an exclusion. In the SDT's comment responses for Texas RE's comments on the initial ballot, the SDT states "In the definition of Reporting ACE asynchronous DC ties between Interconnections are excluded from Reporting ACE and are handled as either a generator or load" and "Reporting ACE has been redefined to require that all DC asynchronous tie lines with other interconnections be represented as Source -S written requirement for the DC ties to be handled in any way.

Calendar Year

Texas RE recommends changing the verbiage from "each calendar year" to "each rolling 12 month period". Specifically, R3 and R5 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the Evidence Retention statements) but the BA may not provide the data based on the RoP Appendix 4C Section 3.1.4.2). Texas RE considers this as a gap in compliance monitoring (and reflect a possible gap in reliability). The SDT assertion that "Since an Audit Period will include at least one entire calendar year" is incorrect. A BA has to be audited AT LEAST once every three years but may be audited more often as needed. As written the BA is non-compliant, per the VSLs, until a calendar year is complete.

Implementation Plan

The BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 (effectively BAL-005-1 itself unless the SDT has some other unapproved process in mind) before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.

VSL Language

Texas RE notes that some of the proposed changes to the Standard language have not been flowed through to all proposed VSLs. Texas RE recommends that the SDT review this language and ensure that the final Standard language is accurately reflected in the corresponding VSLs. For example, in the VSLs for R2 there were only corrections in the Lower VSL language to capture changes in the Standard. The changes should be reflected in the other VSLs associated with R2.

The VSL for R4 should reflect System Operators.

Likes 0	
Dislikes 0	

Response

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	
Answer	
Document Name	

Comment

LG&E/KU have recommended a change to the proposed AGC definition and provided an explanation in the “comments” section for question 1. Other comments regarding BAL-005-1 follow.

Requirement 3:

Frequency is a very important reliability parameter that should be monitored by the Balancing Authority. Currently, BAL-005.02b R8.1 requires that frequency metering be available 99.95% of the time. However, R3 of proposed BAL-005-2 requires frequency metering to be available 99.95% of the time “for the calculation of Reporting ACE.” This added wording appears to create a possible overlap compliance concern with R5. All Balancing Authorities understand the importance of redundant frequency metering and are today required to maintain an availability (through automatic failover) of 99.95%. However, per the latest proposed BAL-005-2 standard not only does frequency need to be available as a reliability parameter but it must be available “for the calculation of Reporting ACE.” If the “system used to calculate Reporting ACE” (addressed in R5) is unavailable then a Balancing Authority could be found non-compliant with both R3 and R5 despite having maintained frequency monitoring availability for any purpose at or above 99.95%. When compared to today’s requirement to maintain a frequency monitoring availability of 99.95%, adding “for the calculation of Reporting ACE” provides no reliability benefit given that the availability of the “system used to calculate Reporting ACE” is required to be 99.5%. LG&E/KU recommends removing the language “for the calculation of Reporting ACE” from R3 as this added language provides no additional reliability benefit.

BAL-005-2 R4 and R6 appear to be duplicative with R2 in the draft version of TOP-010-1. Reporting ACE and the inputs to it are obviously Real-time data necessary to perform Real-time monitoring of the BES. LG&E/KU recommend that R4 and R6 be removed from the BAL-005-2 standard and allow TOP-010-1 R2 to be the single Balancing Authority requirement addressing implementation of an Operating Process or Procedure for Real-time data (which includes Reporting ACE and the scan rate data used to calculate Reporting ACE) quality issues.

The VRF for R5 is listed as “Medium.” This appears to be an administrative function to calculate an entities prior year performance and should be assigned a VRF of “Lower.”

Likes 0	
Dislikes 0	

Response

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1

Answer	
Document Name	

Comment

Tacoma Power assumes that the intent of Requriement R3, Part 3.1, is that the total complement of frequency metering equipment meets the availability specification. For example, if one frequency metering equipment has an availability of 99.94%, but there is another frequency metering equipment available as a fail-over source such that availability of the redundant sources together is equal to or higher than 99.95%, this should be considered compliant. Is this assumption reasonable?

Could the drafting team please clarify how compliance with Requirement R3, Part 3.2, would be addressed if a Balancing Authority periodically tests frequency metering equipment (e.g., annually) and finds that the equipment has fallen out of calibration since the last test? For example, in the case of analog frequency transducers, in particular, the accuracy could stray over time. If a Balancing Authority tests its frequency metering equipment periodically and discovers that the accuracy is now less than 0.001 Hz, the Balancing Authority should not be in violation, since, in this scenario, it is not reasonable for them to have identifed the inaccuracy before the frequency metering equipment went out of calibration.

Tacoma Power assumes that the intent of Requirement R7, Parts 7.1 and 7.2, is not to address the real-time status of common sources, for either scan rate values or hourly megawatt-hour values, or for loss of time synchronization. It seems that these real-time issues would be addressed under Requirement R2, Requirement R6, and/or other requirements and would not necessarily constitute a violation of Requirement R7.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	
Document Name	

Comment

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provide such services and register with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) perform its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that’s the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

CO-1 recommend the following wording for R3:

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE:

3.1 that is available a minimum of 99.95% for each calendar year

3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz.

3.3 checked for accuracy once each calendar year

There was concerns about what quality the ± 0.001 Hz was being applied to.

In the definition of Actual Net Interchange, strike the last sentence since it is too prescriptive. We believe a BA should have the flexibility to either include or exclude the actual transfers across DC tie lines based on the modeling of the facility.

Likes 0	
Dislikes 0	

Response

William Temple - William Temple

Answer	
Document Name	

Comment

PJM proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change.

Additionally, if this standard is to remain, then the name of the standard should be changed. It is now referred to as **Balancing Authority Control,** but the requirements are for **ACE Process Design**. BA Control is addressed by BAL requirements - not by this standard.

REQUIREMENT 2

This requirement is not a reliability-based standard and is not needed. R2 addresses reporting the loss of ACE to an RC. The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE, then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue - not a reliability issue.

It is a good practice that when a BA control center is not functional that it tells the RC, but this is covered elsewhere. IRO-005-3.1a R1.6 requires the RC monitor "Current ACE for all its Balancing Authorities. "

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? PJM suggests that frequency meter accuracy be included in the certification process.

Average availability (R3.1) on the other hand creates a reliability gap, and that as written does not increase reliability. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time.

If an availability requirement is needed, then we suggest tie it into the same time frame as the loss of ACE mandate.

There are two concerns with the way R3 is worded:

a.   With the way R3 reads, it could be misinterpreted that the frequency metering equipment requires an accuracy of 0.001 Hz for 99.95% of the calendar year. That would mean checking (and fixing) your frequency metering device every hour to ensure you do not exceed four hours during a year with a frequency accuracy less than 0.001 Hz. This is not intent of R3 and the requirement should be rewritten. The intent is that the frequency metering equipment is *designed* to have a minimum accuracy of 0.001 Hz.

b.   R3 could also be misinterpreted to mean that a BA's frequency error over an entire year must be 0.001 HZ or less.

PJM believes the requirement should be removed. However if the requirement is not removed PJM submits the following re-wording of R3 for clarity:

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE:

3.1 that is available a minimum of 99.95% for each calendar year

3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz.

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process." Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

Requirement R6 is confusing regarding the term "errors." Are these metering errors such as spikes? Are these Inadvertent Interchange metering errors? The requirement should provide more clarity on this.

The term "scan-rate" should be changed to "scan rate." Nowhere else in the standard or the NERC glossary is this term hyphenated.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

PJM notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

R7 requires the BAs to have a common source. This could possibly pose a conflict with CIP-005-5 R1, which could be interpreted to require a Responsible Entity to have individual access to a meter.

In R7, the word Tie-Line is not defined. In the NERC Glossary it is listed as “Tie Line.”

In R7.2, PJM’s concern here is that errors would be apparent in many more ways (and much more quickly) than by calculating hourly megawatt -h values. This doesn’t appear to be a reliability requirement.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provides such services and registers with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) performs its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that’s the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

If for any reasons Requirement R3 is retained, then we would suggest rewording it to improve clarity. As written, R3 can be interpreted as a continuous accuracy requirement of 0.001 Hz under all conditions including use of secondary or tertiary backup equipment when necessary

under certain conditions. We do not believe this is the intent of the requirement so it needs to be re-worded to not imply a continuous accuracy requirement. If the intent is to use primary frequency metering equipment that has demonstrated or been tested to meet the 0.001 Hz accuracy requirement, then the requirement and/or the measure should be revised to clearly indicate this is the objective/intent.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 3

Answer	
Document Name	

Comment

1. Although it can be viewed as a “resource”, maintaining Interchange obligations is a unique enough task for a Balancing Authority to perform, APS recommends leaving Interchange in as part of the Balancing Authority definition. “…maintains Demand and resource balance within a Balancing Authority Area, while maintaining Interchange obligations, and supports Interconnection frequency in real time.”

2. The wording of R7.2 appears to be combining two requirements. The requirement to have a time-synchronized common source and to agree upon the hourly megawatt-hour values the source provides. These should be separated out as the current verbiage is unclear.

Likes 0	
Dislikes 0	

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3

Answer	
Document Name	

Comment

- The proposed version of BAL-005 is inconsistent with the recommendations of the Independent Experts Review Project and the Results-Based Reliability Standard Development Guidance.
- R1, R3, and R7 are design parameters and should be moved to a Guideline (and reviewed as part of a BA Certification). They are not performance-based, risk-based, or competency-based requirements.
- R4 seems to overlap the proposed TOP-010-1 R2 creating a potentially double-jeopardy.”

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern suggests adding the below wording to the definition of Balancing Authority:

The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, while maintaining scheduled interchange and supporting Interconnection frequency in real time.

Southern Suggests adding the below wording to R1 and M1:

R1. The Balancing Authority shall use a design scan rate not greater than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real -time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate not greater than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change

Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard.

REQUIREMENT 2

This requirement is not a reliability based standard and is not needed.

R2 addresses reporting the loss of ACE to an RC.

The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE?

It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."?

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process.

Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time!

If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 4

Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes "invalid data" and defines "quality" (if the BA is to flag quality then the term should be defined somewhere)

REQUIREMENT 5

Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for “correcting errors in the scanning process” Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

Likes 0	
Dislikes 0	

Response

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

We suggest the Standard be completely revisited to be:

R1. Each BA shall support Interconnection frequency through monitoring Reporting ACE

R2. A Balancing Authority shall maintain adequate metering, communications, and control equipment to prevent becoming a Burden on the Interconnection or other Balancing Authority Areas.

Likes 0	
Dislikes 0	

Response

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	
Document Name	

Comment

The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change

Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard.

REQUIREMENT 2

This requirement is not a reliability based standard and is not needed.

R2 addresses reporting the loss of ACE to an RC.

The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE?

It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."?

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process.

Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time!

If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 4

Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes “invalid data” and defines “quality” (if the BA is to flag quality then the term should be defined somewhere)

REQUIREMENT 5

Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for “correcting errors in the scanning process” Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

Likes 0	
Dislikes 0	

Response

Kelly Dash - Kelly Dash, Group Name Con Edison

Answer	
Document Name	

Comment

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

“The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries.”

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	

Comment

R7.2 Not all tie lines have time-synchronized meters. The adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

SRP appreciates the efforts of the SDT and provides the following comments regarding the changes to BAL-005-1:

· R3 is vague and has the potential for inconsistent implementation as worded.

It is unclear whether the 99.95% availability calculation is to be applied independently to each individual metering point, or whether it should be the average availability of all metering equipment.

· R4 – SRP recommends reducing ambiguity by adjusting the requirement to state “System Operator”.

· R5 – SRP recommends providing clarification on how the 99.5% is to be calculated?

· R6 – SRP recommends rewording the standard to avoid creating the super tem “Balancing Authority Interconnection.

Likes 0

Dislikes 0

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer

Document Name

Comment

Provided in ACES Comments

Likes 0

Dislikes 0

Response

John Fontenot - Bryan Texas Utilities - 1

Answer

Document Name

Comment

na

Likes 0

Dislikes 0

Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC	
Answer	
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 6	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Appelbaum - United Illuminating Co. - 1	
Answer	
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below.

John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP is in support of retiring BAL-006-2	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
The SRC supports the retirement of BAL-006-2.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT joins the IRC SRC in supporting the retirement of BAL-006.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern supports the retirement of BAL-006-2. However, we suggest requirements be included in a commercial alternative arrangement, such as a NAESB standard, rather than a guideline that only suggests approaches and behaviors and is not binding or mandatory.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy supports the retirement of BAL-006-2 in conjunction with the changes in BAL-005 as well as the development of the Guideline document as an integrated package. We feel that implementation of just one of these suggestions, without the others, would not sufficiently maintain reliability concerns with the grid.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

William Temple - William Temple

Answer	
Document Name	

Comment

PJM supports the retirement of BAL-006.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	

Document Name

Comment

We support the retirement of BAL-006-2.

Likes 0

Dislikes 0

Response

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Answer

Document Name

Comment

: LG&E/KU would like to support the retirement of BAL-006 but as of now have questions regarding the guideline and implementation plan. For example, in the transition to a guideline, must existing inadvertent balances be minimized or do existing balances simply disappear?

Likes 0

Dislikes 0

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer

Document Name

Comment

In the BAL-005-1 Implementation Plan there is a reference to retirement of BAL-006-2 under “General Considerations” but further down there is a reference to BAL-006-2 Requirement 3 under “Retirements”. Additionally, there is no reference to BAL-006-2 in the “Requested Retirement” section. Which is correct?

Additionally, the BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.

Likes 0

Dislikes 0

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer

Document Name

Comment

N/A

Likes 0

Dislikes 0

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer

Document Name

Comment

We agree with the SDT in proposing to retire BAL-006-2 and to develop an Inadvertent Interchange Guideline that will be approved by the NERC Operating Committee at a later date.

Likes 0

Dislikes 0

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer

Document Name

Comment

BPA agrees that BAL-006 is an energy accounting standard and not a Reliability Standard. However, guidelines are not enforceable. BPA agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange. BPA proposes adding inadvertent accounting via a NAESB standard or business practice since the **NAESB** WEQ Inadvertent Interchange Payback Standards **already handles certain aspects of Interchange accounting.**

Likes 0

Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tammy Porter - Tammy Porter	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeremy Voll - Basin Electric Power Cooperative - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelly Dash - Kelly Dash, Group Name Con Edison	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Appelbaum - United Illuminating Co. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Likes 0

Dislikes 0

Response

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3

Answer	
Document Name	

Comment

Likes 0

Dislikes 0

Response

Jeri Freimuth - APS - Arizona Public Service Co. - 3

Answer	
Document Name	

Comment

Likes 0

Dislikes 0

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shivaz Chopra - New York Power Authority - 6	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We agree with the removal of the LSE function.

(2) However, we disagree with other proposed modifications in FAC-001-3. It was determined through the Paragraph 81 project that having Facilities within a BA's metered area boundaries are administrative and unnecessary. We suggest removing Requirement R3, part 3.3 and Requirement R4, part 4.3. These are administrative requirements that are not necessary for reliability. Furthermore, the NERC Rules of Procedure Section 501.4.4 already requires NERC to "ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority." There are equally efficient means that are already in effect; therefore, the SDT should remove these requirements, as they are unnecessary.

(3) We recommend extending the implementation plan to 36 months. The proposed 12-month implementation plan is insufficient because interconnection study requests can take as long as 18 months. These could take significant amounts of time if complex issues are encountered during negotiations of interconnection agreements.

(4) We thank the SDT for the opportunity to comment on this standard.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

Its not that we aren't in support of the modifications to FAC-001 however, we have a concern that the documentation mentioned in Rationale 3.3 and 4.3 (Functional Model) isn't currently up to date. We would suggest to the drafting team to verify the latest review of this documentation. Also, we would suggest the drafting team verifying that this document is properly aligned with other documentation such as: The Rules of Procedure (ROP), Glossary of Terms and The Federal Power Act for consistency and reliability of the BES. Additionally, we would like for the drafting team to review the concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA in association referenced to BAL-005-0.2b Requirement R1 parts R1.1, R1.2 and R1.3. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

Likes 0	

Dislikes 0

Response

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer

Document Name

Comment

While TVA supports the intent of addressing the metered boundaries of the Balancing Authority Area in FAC-001-3, we believe the language of R3, part 3.3, and R4, part 4.3, needs to be improved. We recommend that wording similar to that used in the rationale statements be used in the requirement sub-parts as follows:

R3, part 3.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

R4, part 4.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

As currently written in Draft 2, R3, part 3.3, appears to focus on "transmission Facilities" and ignores generation Facility and end-user Facility connections. Similarly, R4, part 4.3, appears to focus on "generation Facilities" and ignores transmission Facility and end-user Facility connections.

Likes 0

Dislikes 0

Response

Jason Snodgrass - Georgia Transmission Corporation - 1

Answer

Document Name

Comment

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to "commissioning of a Facility" which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term "study" within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC's desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Likes 0	
Dislikes 0	

Response

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1

Answer	
Document Name	

Comment

While the latest proposed revisions to FAC-001-3 are an improvement (by removing the unnecessary R5, R6 and R7), the additions of R3.3 and R4.3 could be better worded, are unnecessary as requirements (they attempt to address an energy accounting problem, not a reliability problem), and likely already included in most Facility Interconnection Requirements documents in the Metering and Telecommunications section under Guidelines and Technical Basis (created in the new FAC-001-2), and/or in interconnection agreements between Facility owners and transmission providers.

If the SDT chooses to retain these requirements, some changes in the wording are warranted: R3.2 reads, “Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.” In order to understand the sentence, it is helpful to make a substitution like the following: “Procedures for notifying [someone] of new [things].”

The new R3.3 reads: “Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area’s metered boundaries.” A simple fix might be to change the word “of” to “that” so that it reads “Procedures for confirming with [someone] that new [things] are within a Balancing Authority Area’s metered boundaries.”.

Likes 0	
Dislikes 0	

Response

Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC

Answer	
Document Name	

Comment

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to “commissioning of a Facility” which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3 and IRO-010-2. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term “study” within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC’s desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	
Document Name	

Comment

The added requirements 3.3 and 4.3 are not clear. The drafting team copied R3.2 approach but it not work for 3.3. In R3.2 the Transmision Owner is notifying the other reliability entities that new or modified interconnection is being pursued. Technically that would include a notice to the BA. But an explicit sub-requirement is needed. Concerns with R3.3 are: 1. Use of word confirming. Confirming is beyond notification; a confirmation requires the TO to maintain the response from the BA and possibly go further and verify the BA is truthful. The SDT reply to the last comments indicated it was really concerned that the BA would not be aware of changes made by TO. 2. The use of phrase “those responsible for the reliability of affected systems” is not needed and should be replaced with ‘responsible Balancing Authority’ since that is the only reliability function implicated by this subrequirement. 3.The BA should be required to provide the procedure for notification from a TO when a new or modified interconnesction is being pursued. Then the TO can align its Interconnection requirements document to the BA process.

We do not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated “It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA’s metered boundaries”. We do not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read “Entity seeking to interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area’s metered boundaries”

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2. FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

Likes 0	
Dislikes 0	

Response

William Temple - William Temple

Answer	
Document Name	

Comment

PJM views FAC-001 as a reporting requirement that must be carefully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change." The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirement as part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility owner is required to register with NERC. PJM proposes that as part of that process, the facility owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entity(ies) that are involved.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

Likes 0	
Dislikes 0	

Response

Shivaz Chopra - New York Power Authority - 6

Answer	
Document Name	

Comment

FAC-001-3. ***NYPA has a concern that R3.3 and 4.3 should be the responsibility of the interconnecting entity to ensure their facility is within a BA's metered boundary***.

Likes 0	
Dislikes 0	

Response

Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance

Answer	
Document Name	

Comment

The SDT should consider the impact of new requirements R3.3 and R4.3 in regions where a single BA exists. These requirements would not seem to apply in cases such as ERCOT, where clearly any TO or GO facility additions are within the one and only BA's metered boundaries.

Recommend the standard language additions:
3.3 In regions with multiple Balancing Authorities, procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

4.3 In regions with multiple Balancing Authorities, Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment

na

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy is not certain that the current language in R3.3 and R4.3 of the proposed FAC-001-3 adequately establishes that it is the responsibility of the interconnecting entity to make the necessary arrangements, and that the Transmission Owner is responsible for confirming with a Generator, who their Balancing Authority will be. We feel that this intent is clear from reading the Rationale for R3, but do not feel that this intent is ascertainable by reading R3.3 on its own. Duke Energy suggests the following revisions to R3.3 and R4.3 to add clarity:

R3.3: Procedures for confirming that new or materially modified transmission Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

R4.3: Procedures for confirming that new or materially modified generation Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

We feel that these modifications and the resulting modifications to the Guidelines and Technical Basis section of the standard, better illustrates the intent of the drafting team, without needing the requirements' rationale to decipher said intent.

Also, Duke Energy suggests a minor modification to language used in the sub-requirements of R3 and R4. We suggest the use of the term Procedure[s] with the [s] accompanying. This clears up ambiguity that could arise in the event that an entity only has one procedure that is applicable to these requirements.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

APS agrees with the approach for Requirements R3.3 and R4.3, in that it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority, and that the Transmission Owner or Generation Owner is responsible for confirming that the party interconnecting to make appropriate arrangements with a Balancing Authority. Since Transmission Owners and Generation Owners may receive either transmission or generation interconnection requests, APS recommends revising the requirements as follows:

R3.3 – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries.

R4.3 – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

ReliabilityFirst agrees the draft FAC-001-3 draft standard but offers the following comments for consideration.

1. **Requirement 3, Part 3.3**
   i. **Part 3.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified transmission Facility".**
2. **Requirement 4, Part 4.3**
   i. **Part 4.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified generation Facility".**

Likes 0	
Dislikes 0	

Response

Jonathan Appelbaum - United Illuminating Co. - 1

Answer	
Document Name	

Comment

1. R3.2 has the TO establishing a procedure to provide a notification whle R3.3 requires a confirmation. What is the difference in actions between notification and confirmation? Who or what is to be confirmed? The technical and guideline section should explain what the confirmation is supposed to be.

2. Do requirements R3.2 and R3.3 means the TO must perform this confirmation or can the procedure require the interconnecting party perform the confirmation? UI believes the TO establishes the procedure, or writes into its interconnection document the BA's process, but the requirements document can require the interconnecting party to perform the notifiction and confirmation. If so, this should be added to the Technical Guideline section of Standard.

3. What is the purpose of R3.3 requiring a confrimation with " those responsible for the reliability of affected systems" instead of just stating the Balancing Authority. It should be the BA..

This is my proposed addition to Techincal Guideline section to address my comments 1 to 3:

"R3.2 requires the TO to establish a procedure to notify those responsible for the reliability of affected system(s) of new or materially modified existing interconnections. Notification means that the TO, requires either itself or the interconnecting party to contact the relevant reliability authorities and provide notice of the facility. R3.3 requires the TO to establish a procedure to confirm that a facility is within a metered boundary of a BA. Confirmation means that the TO, requires either itself or the interconnecting party to contact the BA and receive a letter of confirmation that the facility is in the BA metered boundary. The requirement and measure for R3 is only that the processes are established in the requirements document. The requirements document may reference a market or tariff as its process."

4. If proposed R3.3 was to be approved then it is missing the word "that". It should state: "Procedures for confirming with those responsible for the reliability of affected systems **that** new or materially modified transmission Facilities are within a Balancing Authority Area’s metered boundaries.."

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb

Answer	
Document Name	

Comment

KCP&L does not support the proposed revisions to FAC-001-3 R3.3 and recommends not adopting the Requirement. The proposed revised Standard is applicable to KCP&L as a registered Transmission Owner and, potentially, as a registered Generator Owner.

Requirement 3.3

R3.3 creates a compliance obligation for a disinterested party. The proposed R3.3, in effect, requires the Transmission Owner to create a procedure to promote the exchange of information between a third party Facility interconnecting with a Generator Owner whose facility is used to connect to the Transmission system. The procedure developed by the Transmission Owner must identify "affected systems," confirm who is responsible for reliability of the "affected systems," and, confirm with the "affected systems" owner that new interconnected facilities are within the metered boundaries of the identified Balancing Authority.

The difficulty with R3.3, as proposed, is evident when compliance scenarios are considered. For example, the Transmission Owner creates the required procedure under R3.3. The rationale—the compliance goal—for R3.3 centers on a duty by of the party interconnecting (PI) to make appropriate arrangements with the BA to ensure the PI Facilities are within the BA's metered boundaries. If the PI fails to fulfill its duty, it raises the question: Where is the noncompliance under R3.3? The Transmission Owner created the procedure, as required, yet, the stated rationale, goal, is not accomplished.

To achieve the stated rationale's goal, It would seem the compliance duty should fall to the party interconnecting. Absent that, the Balancing Authority and/or the Generator Owner whose facilities are used to interconnect to the transmission system would be in a better position to address Balancing Authority Area's metered boundaries. Also, the Requirement seems redundant since there are active NERC Standards requiring Generator Owners to inform Transmission Owners of changes to the GOs' facilities and Transmission Owners informing BA of new interconnections. Finally, from a practical viewpoint, it is just not likely a PI would connect without metering and SCADA connections—all such activity providing visibility to the BA and TO of changes to the system.

KCP&L recommends removing R3.3 or, in the alternative, suggests deleting "with those responsible for the reliability of affected systems of" from the proposed R3.3.

R3.3: "Procedures for confirming ~~with those responsible for the reliability of affected systems of~~ new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries."

"Affected System"

Generally, defined terms better serve compliance with Standards and implementation of Requirements. The term, "affected system" is not defined. FERC approved *pro forma* interconnection agreements define the term as, "...an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection." KCP&L believes there may be benefit aligning the undefined NERC Standard terms relating to interconnection facilities with equivalent FERC *pro forma* interconnection agreements defined terms. While such an effort would require substantial effort to address all affected Standards, for the purposes of this Standard, we would encourage adopting FERC's *pro forma* definition for the proposed revision to FAC-001-3.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

Likes 0	
Dislikes 0	

Response

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

This standard should not be a reliability standard, the contents of the standard do nothing to improve the reliability of the system.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities

Answer	
Document Name	

Comment

Exelon thinks R3 (and R4) needs to be re-written. We suggest:

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements for new or materially modified existing interconnections:

3.1. Procedures for coordinated studies of new or materially modified interconnections and impacts on affected system(s).

3.2. Procedures for notifying responsible entities of affected systems identified in part 3.1.

3.3. Procedures for confirming with responsible entities that that the new or modified Facilities are within a Balancing Authority Area's metered boundaries.

We also note that the phrase "materilaly modifed" may be subject to interpretation during an audit. The Guideline and Technical Basis section allows the use of engineering judgement when determing what is "material". It seems to beg the question, if an entity is using it's interconnection process and associated procedures as required by the Standrd, the change is material. Has the SDT considerd removing material from the language? This phrase is not defined or used in any other standard other than FAC-001 and 002. We believe either of these changes are non-substantive and would not require an additional comment period.

Likes 0	
Dislikes 0	

Response

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee

Answer	
Document Name	

Comment

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

Likes 0	
Dislikes 0	

Response

Kelly Dash - Kelly Dash, Group Name Con Edison

Answer	
Document Name	

Comment

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2.   FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 1,3,5

Answer	
Document Name	

Comment

this needs work & here my support for the overall theme of comments submitted by MRO-NSRF, SCR, and also Oncor.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 3

Answer	
Document Name	

Comment

R3.3 and R4.3: The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

Likes 0	
Dislikes 0	

Response

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	

Comment

R3.3 and R4.3 The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

Likes 0	
Dislikes 0	

Response

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

SRP is in support of the proposed FAC-001-3

Likes 0	
Dislikes 0	

Response

Tammy Porter - Tammy Porter

Answer	
Document Name	

Comment

Oncor does not support the proposed changes to R3. The SDT, in the rationale box states “the Transmission Owner is responsibile for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries”. Oncor does not believe that the Transmission Owner should be responsible for the compliance of the interconnecting Transmission Owner. Therefore, Oncor recommends changing R3.3 to the following: "3.3. Requirement that new or materially modified transmission Facilities of the interconnecting Transmission Owner are within a Balancing Authority Area's metered boundaries."

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

Provided in ACES Comments

Likes 0	
Dislikes 0	

Response

Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion does not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated “It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA’s metered boundaries”. Dominion does not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read “Entity seeking to interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area’s metered boundaries”

Likes 0	
Dislikes 0	

Response

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	

Comment	
na	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-2 & FAC-001-3
Comment Period Start Date:	11/10/2015
Comment Period End Date:	1/11/2016
Associated Ballots:	2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-006-2 IN 1 ST 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 IN 1 ST

There were 43 responses, including comments from approximately 117 different people from approximately 84 companies representing 8 of the 10 Industry Segments as shown in the table 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. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below. JR

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below. JR

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RFC	ISO Standards Review Committee	Charles Yeung	PJM Interconnection, L.L.C.	2	SPP
					Ben Li	PJM Interconnection, L.L.C.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RFC
					Kathleen Goodman	PJM Interconnection, L.L.C.	2	NPCC
					Greg Campoli	PJM Interconnection, L.L.C.	2	NPCC
					Ali Miremadi	PJM Interconnection, L.L.C.	2	WECC
					Terry Bilke	PJM Interconnection, L.L.C.	2	RFC
					Liz Axson	PJM Interconnection, L.L.C.	2	TRE

ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	ACES Power Marketing	1	RFC
					Ginger Mercier	ACES Power Marketing	1,3	SERC
					Ellen Watkins	ACES Power Marketing	1	SPP
					Michael Brytowski	ACES Power Marketing	1,3,5,6	MRO
					John Shaver	ACES Power Marketing	4,5	WECC
					John Shaver	ACES Power Marketing	1	WECC
					Shari Heino	ACES Power Marketing	1,5	TRE
					Kevin Lyons	ACES Power Marketing	1	MRO
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	Exelon	1	RFC
					John Bee	Exelon	3	RFC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RFC,SERC	Duke Energy	Doug Hils	Duke Energy	1	RFC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RFC
Lower Colorado River Authority	Dixie Wells	5		LCRA Compliance	Michael Shaw	Lower Colorado River Authority	6	TRE
					Teresa Cantwell	Lower Colorado River Authority	1	TRE
					Dixie Wells	Lower Colorado River Authority	5	TRE

MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	MRO	3,4,5,6	MRO
					Chuck Lawrence	MRO	1	MRO
					Chuck Wicklund	MRO	1,3,5	MRO
					Dave Rudolph	MRO	1,3,5,6	MRO
					Kayleigh Wilkerson	MRO	1,3,5,6	MRO
					Jodi Jenson	MRO	1,6	MRO
					Larry Heckert	MRO	4	MRO
					Mahmood Safi	MRO	1,3,5,6	MRO
					Shannon Weaver	MRO	2	MRO
					Mike Brytowski	MRO	1,3,5,6	MRO
					Brad Perrett	MRO	1,5	MRO
					Scott Nickels	MRO	4	MRO
					Terry Harbour	MRO	1,3,5,6	MRO
					Tom Breene	MRO	3,4,5,6	MRO
					Tony Eddleman	MRO	1,3,5	MRO
					Amy Casucelli	MRO	1,3,5,6	MRO
Kelly Dash	Kelly Dash		NPCC	Con Edison	Kelly Dash	Kelly Dash	1,3,5,6	NPCC
					Edward Bedder	Kelly Dash	NA - Not Applicable	NPCC
Dominion - Dominion Resources, Inc.	Louis Slade	6		Dominion	Randi Heise	Dominion - Dominion Resources, Inc.	5,6	NPCC

					Connie Lowe	Dominion - Dominion Resources, Inc.	1,3,5,6	SERC
					Louis Slade	Dominion - Dominion Resources, Inc.	5,6	RFC
					Chip Humphrey	Dominion - Dominion Resources, Inc.	5	SERC
					Nancy Ashberry	Dominion - Dominion Resources, Inc.	5	RFC
					Larry Nash	Dominion - Dominion Resources, Inc.	1,3	SERC
					Candace L Marshall	Dominion - Dominion Resources, Inc.	1,3	SERC
					Larry W Bateman	Dominion - Dominion Resources, Inc.	1,3	SERC
					Jeffrey N Bailey	Dominion - Dominion Resources, Inc.	5	SERC
					Russell Deane	Dominion - Dominion Resources, Inc.	5	NPCC
Southern Company - Southern	Marsha Morgan	1,3,5,6	SERC	Southern Company	Robert Schaffeld	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					John Ciza	Southern Company - Southern Company Services, Inc.	6	SERC
					R Scott Moore	Southern Company - Southern Company Services, Inc.	3	SERC
					William Shultz	Southern Company - Southern Company Services, Inc.	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no UI O&R	Paul Malozewski	Northeast Power Coordinating Council	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Brian Shanahan	Northeast Power Coordinating Council	1	NPCC
					Rob Vance	Northeast Power	1	NPCC

						Coordinating Council		
					Mark J. Kenny	Northeast Power Coordinating Council	1	NPCC
					Gregory A. Campoli	Northeast Power Coordinating Council	2	NPCC
					Randy MacDonald	Northeast Power Coordinating Council	2	NPCC
					Wayne Sipperly	Northeast Power Coordinating Council	4	NPCC
					David Ramkalawan	Northeast Power Coordinating Council	4	NPCC
					Glen Smith	Northeast Power Coordinating Council	4	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC

					Brian Robinson	Northeast Power Coordinating Council	5	NPCC
					Bruce Metruck	Northeast Power Coordinating Council	6	NPCC
					Alan Adamson	Northeast Power Coordinating Council	7	NPCC
					Kathleen M. Goodman	Northeast Power Coordinating Council	2	NPCC
					Helen Lainis	Northeast Power Coordinating Council	2	NPCC
					Michael Jones	Northeast Power Coordinating Council	3	NPCC
					Silvia Parada Mitchell	Northeast Power Coordinating Council	4	NPCC
					Connie Lowe	Northeast Power	4	NPCC

						Coordinating Council		
					Michael Forte	Northeast Power Coordinating Council	1	NPCC
					Sylvain Clermont	Northeast Power Coordinating Council	1	NPCC
					Si Truc Phan	Northeast Power Coordinating Council	2	NPCC
					Kelly Silver	Northeast Power Coordinating Council	3	NPCC
					Brian O'Boyle	Northeast Power Coordinating Council	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jason Smith	Southwest Power Pool, Inc. (RTO)	2	SPP
					Jim Nail	Southwest Power Pool, Inc. (RTO)	3,5	SPP

					Mike Kidwell	Southwest Power Pool, Inc. (RTO)	1,3,5	SPP
					Kevin Giles	Southwest Power Pool, Inc. (RTO)	1,3,5,6	SPP

1. The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment

Modifying the definition of Balancing Authority would misalign the term with the definition found in the NERC Rules of Procedure. SRP recommends retaining the current definition of Balancing Authority.

The proposed definition of AGC combines defined terms to create the phrase “Balancing Authority Area Demand” ERC recommends rephrasing the definition to avoid using one defined term to modify another. An alternative might be “Demand within a Balancing Authority Area”.

Primary Inadvertent Interchange is not a NERC defined term. It is a defined WECC term, SRP recommends adding Primary Inadvertent Interchange to the terms used continent wide. as the revised ATEC definition will be effective continent wide.

SRP recommends removing or defining terms capitalized but not defined in the NERC Glossary of Terms such as Control Area and Balancing Area. Capitalizing terms that are not defined creates confusion even when used in the rationale areas.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team will work with NERC staff to request a change to the NERC Rules of Procedure to align the definitions.

Thank you for your comment. As written, the standard uses “Balancing Authority Area” and “Demand” as two separate defined terms. The SDT does not intend for the terms to be combined into one term.

Thank you for your comment, Primary Inadvertent Interchange is defined in the proposed continent wide term "ATEC."

Thank you for your comment. The drafting team will review the standard and eliminate any capitalized term not defined.

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	

The definition of AGC is fine, but in the process of combining the need for common sources regarding MW and MWh values into the proposed R7, the association between AGC, ACE, MW, and MWh quantities is less clear. The user now has to combine the definitions for AGC, Reporting ACE, and R7 to get an equivalent picture compared to the original requirement. Maybe some references or revised wording in R7 would help clarify the expectations.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team is developing a guideline which should clarify expectations for Functional Entities.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy suggests a modification to the proposed definition of Automatic Generation Control (AGC), which we feel would enhance clarity and maintains the assumed intent of the drafting team. We recommend the following:

Automatic Generation Control (AGC): A process designed and used to automatically adjust a Balancing Authority Area's Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

We feel that the above definition adds clarity, and with the addition of the term automatically in the definition, more adequately describes the function that AGC provides.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The drafting team agrees with your clarification and has updated the definition accordingly. This revision is not a substantive change, as the SDT has always intended for AGC to "automatically" adjust a Balancing Authority Area's Demand and resources to maintain Reporting ACE. This intent is reflected in the Rationale for AGC.

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

HQT believes that Requirement 7 should apply specifically to tie lines, pseudo-ties and dynamic schedules that included in the ACE equation. Even though having the same scan-rate measure and having a time synchronized common source is a good practice, Tie-lines that are not included in the ACE equation that are not equipped with such will not affect adversely the control of a balancing authority. HQT proposes to modify R7 as below:

7. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority **that is included in the ACE equation** is equipped with: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The drafting team believes the requirement as drafted assures reliable operation at all times and does not leave any doubt in the handling of information.

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

These comments are submitted on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") LG&E/KU are registered in the SERC region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

The BARC 2.1 SDT has modified the definition of AGC and Pseudo Tie. Do you agree that the proposed modifications provide sufficient clarity? If not, please explain in the comment area below.

Yes

No X

Comments: LG&E/KU recommend the AGC definition be modified to add flexibility as follows:

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Area's Demand, Interchange, or resources, as applicable, to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

"Demand" is defined in the NERC Glossary as the rate at which energy is used by the customer. As written, the AGC definition could be interpreted to mean a BA is required to utilize Demand controls to adjust ACE. A BA should not be expected to use Demand controls to adjust ACE because the real-time nature of ACE and some current forms of Demand controls are not necessarily compatible. Additionally, the SDT's proposed definition does not mention Interchange which is a component of ACE and can be used to adjust ACE. Because Interchange has not typically been understood to be included in the term "resources," LG&E/KU recommend "Interchange" be expressly included in the definition of AGC. If the SDT does not accept the above recommendation, should it be the industry's understanding that the term "resources" includes Interchange?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the clarification change to the definition. There was never any intent in the original definition that AGC was inclusive of Demand and resources. Also, Interchange is included in the defined term "Reporting ACE."

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer	No
Document Name	

Comment

Texas RE recommends that the SDT consider the impact of changing the definition of Automatic Generation Control (AGC) on other NERC Glossary definitions prior to implementing such a change in this project. Although the SDT's stated goal of converting the AGC definition from a prescriptive "how to" requirement to an arguably more flexible, performance-based approach is laudable, Texas RE notes that AGC is used in other NERC Glossary definitions and, as currently defined, represents a commonly understood term in the industry. For example, the term AGC is used in the following defined terms: Anti-Aliasing Filter, Overlap Regulation Service, and proposed Remedial Action Scheme. Accordingly, modifying the AGC definition in one context without considering the consequences of such a change for other defined terms could introduce unnecessary uncertainty and confusion, as well as lead to unintended consequences. In light of the interlocking usage of AGC, Texas RE recommends that the SDT either retain the existing AGC definition or, at a minimum, consider the impact of changing the AGC definition as part of this project prior to making any changes.

If the SDT does move forward with the proposed changes to the AGC definition, Texas RE recommends revising the proposed definition slightly to correct what appears to be a typographical error. Specifically, Texas RE believes the phrase "that of" should be struck so that the proposed AGC definition reads: "A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE *in a* Balancing Authority Area within the bounds required by applicable NERC Reliability Standards."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has made minor conforming modifications to the definition.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 – WECC

Answer	No
Document Name	

Comment

BPA disagrees with the modified definition of AGC; AGC is equipment or a system, not a process. Also, BPA suggests that the clause "...in that of a BAA..." could be simplified to "in a BAA."

Regarding the modified definition of Pseudo-Tie, BPA requests clarification of what constitutes an "alternate control process."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees and has made minor modifications to the definition. Regarding your question about "alternate control process", an alternate control process could mean manual control.

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern suggests the below change to the definition of AGC:

A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has made minor conforming modifications to the definition.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	Yes
Document Name	

Comment

The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be:

"A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards."

Please check and revise as appropriate.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has made minor conforming modifications to the definition.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
We would suggest to the drafting team to develop a rationale box for the modification of the Pseudo Tie definition as they did for the AGC definition. We feel this would help provide clarity on why the drafting team made the modifications to this term’s definition and how this change will have an impact on the reliability of the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT does not believe a rationale box is necessary for the Pseudo Tie Definition.	

John Fontenot - Bryan Texas Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shivaz Chopra - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
William Temple - William Temple	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

The phrase "..help maintain the Reporting ACE in that of a Balancing Authority Area …" in the revised definition reads a bit awkward. We interpret the definition is meant to be:

"A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE of a Balancing Authority within the bounds required by applicable NERC Reliability Standards."

Please check and revise as appropriate.

Likes 0	
Dislikes 0	

Response

Thank you for your recommendation. The SDT has made minor conforming modifications to the definition.

2. If you are not in support of the proposed modifications to BAL-005-1, please provide your objection(s) and proposed solution(s) in the area below.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

R1: BPA requests definition of "design scan rate" as identified in the R1. Scan rate is not a defined term in the NERC Glossary. It is unclear to what the SDT means by design scan rate and why the word "design" was added in this second draft.

R6: BPA still has concerns as to how R6 would be met. This requirement seems subjective and open-ended; it would be difficult for an auditor to apply a consistent metric or method to validate compliance. BPA proposes the following: "Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to ensure the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. The process must accomplish the following:
a. Compare MWh values from common source meters to integrated scan rate values
b. Xxx
c. Xxx

In **R7.1** BPA requests "information....for the scan rate values used in the calculation of Reporting ACE" be defined. BPA is unsure how to address the dynamic schedule portion of this requirement.

In **R7.2**, many dynamic schedules do not have MWH meters; the MWH value is simply the integrated scan rate data for the dynamic schedule. BPA proposes 7.2 be modified to read:
7.2 for all Tie-Lines and metered Psuedo-Ties and metered Dynamic Schedules, a time-synchronized common source to determine hourly megawatt-hour values agreed upon to aid in the identification and mitigation of errors.

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The word "design" was added to the term scan rate to assure that when a BA's EMS missed an occasional scan of data that the BA would not be held to be non-compliant with the requirement.

R6. Thank you for your comment. An Operating Process that would meet the intent of R6. is described in Section VIII. - Special Conditions and Calculations under the Title I_{ME} (Interchange Meter Error). The SDT decided the requirement should not define the specific process because it may vary from BA to BA. Therefore, the process is defined in general terms rather than specifically.

R7.1 & 7.2 Thank you for your comment. The STD intentionally left the word "meter" out of the requirement to allow BA's to use other common sources of data to support the correct calculation of ACE. The important part of the requirement is not where that data comes from. The important part of the requirement is that each BA use scan rate data based on the same source having the same value. This source could be a calculated schedule, a fixed value, or a common metering point. An integrated value is also acceptable for the synchronized value as long as it is integrated from the same source so that errors can be identified when they occur.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We continue to have concerns with Requirement R4 and the approach taken in the wording of this requirement. We agree with the SDT that bad data quality will lead to an inaccurate ACE calculation. However, we feel the SDT should move away from concerns over data quality and instead focus on Reporting ACE calculation capabilities, as it is used by System Operators as a primary metric in making critical operating decisions.

(2) The term "operator" in Requirement R4 is too broad and the SDT should replace it with "System Operator." When we previously identified this as a concern, the SDT's response was that "By using the term operator, the BA will assure the information is provided to the correct personnel." Balancing Authorities are already required to identify such personnel as System Operators in PER-003-1 R3. The SDT should use the System Operator glossary term to align with other reliability requirements and to avoid confusion.

(3) We suggest that Requirement R5 be removed because there is an equally efficient and suitable manner of achieving the reliability result through the NERC Event Analysis (EA) Process. The EA Process, category 1h, requires entities to report when there is a loss of monitoring or control at a Control Center, and could include Reporting ACE calculation capabilities. Hence, this requirement would then be unnecessary.

(4) The SDT assumes that all tie lines between Balancing Authorities use time-synchronized meters. This may not always be true. We recommend the removal of the term "time synchronized" in Requirement R7, Part 7.2 and allow Balancing Authorities to continue to

operate to a common source when conducting their end-of-hour checks with their Adjacent Balancing Authorities. We also recommend the expansion of the VSLs for Requirement R7 where failure to meet one part would be High, and failure to meet both would be Severe.

Likes 0	
Dislikes 0	

Response

(1) Thank you for your comment. The SDT is unclear with respect to your suggested change.
(2) Thank you for your comment. The SDT believes the term operator is appropriate to reflect the differences within BAs. In the context used the term operator only applies to the BA operator, while the term System Operator includes the Transmission Operator, Generation Operator and Reliability Coordinator.
(3) Thank you for your comment. The NERC Event Analysis Process (EA) only requires reporting of a loss of monitoring or control, it does not include any requirement with respect to how often or how long a loss of monitoring or control is acceptable for reliability.
(4) Thank you for your comment. If the meters used for determining MWh values are not time synchronized, then the Operating Process required in R6 would not be valid. Time synchronization is intended to include all forms, such as accumulator freeze pulses, and not to require a specific time synchronizing mechanism. The SDT believes that Requirement R7, as written, is binary in nature. If a requirement is binary then it can only have one VSL, Severe.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

We have a concern pertaining to Requirement R3 parts 3.1 and 3.2. Our group would suggest that the drafting team provide clarity on what are the intents for this particular Requirement and its parts. At this particular time, we are interpreting that the frequency source has to be within 1mHz accuracy for 99.95% of the year.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees with your interpretation of the requirement.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 -– SERC	
Answer	
Document Name	
Comment	
In R6 the SDT is using a new term called “scan rate data” which is not a defined term. This term is rather ambiguous. The phrase “affecting the accuracy of data” is clear enough. Or possibly say the accuracy of data used in calculating ACE. In 7.1 the SDT uses a term called “scan rate values”. The scan rate is how fast we collect the data, it is not the type of data used here. All SCADA data has a scan rate, this could really be referring to almost anything.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the use of the term “scan-rate data” is more specific than the term “data” and applies to the specific Operating Process required in R6.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	
Requirement R1: Scan Rate In reading Requirement R1 and M1, it is unclear whether or not there is a requirement to utilize a scan rate. R1 indicates “The Balancing Authority shall use a design scan rate…” This almost looks like it should read “The Balancing Authority shall use a scan rate” OR “The Balancing Authority shall design a scan rate”. Texas RE recommends there be a requirement to both design and utilize a scan rate as it increases the integrity of data during events as indicated by the rationale.	

Requirement R4: System Operator

As previously submitted for the initial ballot, Texas RE recommends the SDT use the term “System Operator” in R4. The rational states “System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculations are incorrect, the operator should be made aware through visual display. When an operator questions the validity of the data, actions are delayed and the probability of adverse events occurring can increase.” The definition of System Operator is “An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.” The response provide by the SDT to this issue was “The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.” A System Operator needs to be aware of any data issues to make the correct decisions. A BA can provide the information to any other personnel it so desires but the System Operator must, at a minimum, have access to the Reporting ACE information. As written, and interpreted by the SDT, there could be possible gaps in providing the individuals whose responsibility it is to monitor and control that electric system in real time correct information. There may not be consistency within Balancing Authorities as to who the “operator” is in this requirement. Texas RE suggests the verbiage “System Operator and other personnel (as determined by the BA)” to provide clarity. As is, if a System Operator does not have the information the Balancing Authority will be compliant but may hinder reliability by delaying actions and increasing the probability of adverse events occurring. The non-definitive term “operator” will inherently inject non-uniformity in determining compliance. Each entity will have a different interpretation of what “operator” means which will appear as an inconsistency in the Regional Entity review. If an “operator” who is not a System Operator is making and acting on decisions that control the electric system in real time, is that not a concern of the SDT?

Requirement R6: Singe Balancing Authority Interconnection

Texas RE noticed R6 does not address a single Balancing Authority Interconnection. Texas RE recommends there be a requirement for an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in calculating Reporting ACE even in single Balancing Authority Interconnections.

Reporting ACE

Texas RE recommends the standard language explicitly state how DC ties should be handled rather than indicating an exclusion. In the SDT’s comment responses for Texas RE’s comments on the initial ballot, the SDT states “In the definition of Reporting ACE asynchronous DC ties between Interconnections are excluded from Reporting ACE and are handled as either a generator or load” and “Reporting ACE has been redefined to require that all DC asynchronous tie lines with other interconnections be represented as Source-Sink pairs and excluded from Reporting ACE“ yet there is no written requirement for the DC ties to be handled in any way.

Calendar Year

Texas RE recommends changing the verbiage from "each calendar year" to "each rolling 12 month period". Specifically, R3 and R5 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the Evidence Retention statements) but the BA may not provide the data based on the RoP Appendix 4C Section 3.1.4.2). Texas RE considers this as a gap in compliance monitoring (and reflect a possible gap in reliability). The SDT assertion that "Since an Audit Period will include at least one entire calendar year" is incorrect. A BA has to be audited AT LEAST once every three years but may be audited more often as needed. As written the BA is non-compliant, per the VSLs, until a calendar year is complete.

Implementation Plan

The BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 (effectively BAL-005-1 itself unless the SDT has some other unapproved process in mind) before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.

VSL Language

Texas RE notes that some of the proposed changes to the Standard language have not been flowed through to all proposed VSLs. Texas RE recommends that the SDT review this language and ensure that the final Standard language is accurately reflected in the corresponding VSLs. For example, in the VSLs for R2 there were only corrections in the Lower VSL language to capture changes in the Standard. The changes should be reflected in the other VSLs associated with R2.

The VSL for R4 should reflect System Operators.

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The word "design" was added to the term "scan rate" to assure that when a BA's EMS missed an occasional scan of data that the BA would not be held to be non-compliant with the requirement.

R4: Thank you for your comment. If the term is changed as you suggest, it would require the BA to make ACE available to all System Operators (Generation, Transmission, and Reliability Coordinators) within their BA. This goes far beyond the intent of the requirement.

R6: Thank you for your comment. The SDT determined that there is only one scan-rate value, for the Actual Frequency, used in calculating the ACE for a single BA interconnection. The accuracy of Actual Frequency is covered in R3, and therefore, does not need to be included in this requirement.

Reporting ACE: Thank you for your comment. The SDT does not agree that a requirement for modeling asynchronous DC Tie Lines with another Interconnection as source sink pairs should be required for reliability purposes. When managed as a source sink pair, the DC Tie Line would have the same effect as any other load or generation, which is not required to be monitored in any specific standard.

Calendar Year: Thank you for your comment. The SDT has considered your comment at length. However, we believe such an interpretation is too strict and would lead to multiple issues throughout Reliability Standards referring to any time duration.

Implementation Plan: Thank you for your comment. The SDT intends to file the proposed modifications prior to July 1, 2016 in compliance with the FERC directive. In addition, the proposed modification to the Reporting ACE definition incorporating thee ATEC term has no impact on reliability since the WECC Regional Standard includes the ATEC definition.

VSL Language: Thank you for your comment. The SDT has reviewed the language for Requirement R2 and made the appropriate changes. The SDT has not modified the language to state System Operator instead of operator, therefore the VSL should not include the term System Operator.

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

LG&E/KU have recommended a change to the proposed AGC definition and provided an explanation in the “comments” section for question 1. Other comments regarding BAL-005-1 follow.

Requirement 3:

Frequency is a very important reliability parameter that should be monitored by the Balancing Authority. Currently, BAL-005.02b R8.1 requires that frequency metering be available 99.95% of the time. However, R3 of proposed BAL-005-2 requires frequency metering to be available 99.95% of the time “for the calculation of Reporting ACE.” This added wording appears to create a possible overlap compliance concern with R5. All Balancing Authorities understand the importance of redundant frequency metering and are today required to maintain an availability (through automatic failover) of 99.95%. However, per the latest proposed BAL-005-2 standard not only does frequency need to be available as a reliability parameter but it must be available “for the calculation of Reporting ACE.” If the “system used to calculate Reporting ACE” (addressed in R5) is unavailable then a Balancing Authority could be found non-compliant with both R3 and R5 despite having maintained frequency monitoring availability for any purpose at or above 99.95%. When compared to today’s requirement to maintain a frequency monitoring availability of 99.95%, adding “for the calculation of Reporting ACE” provides no reliability benefit given that the availability of the “system used to calculate Reporting ACE” is required to be 99.5%. LG&E/KU recommends removing the language “for the calculation of Reporting ACE” from R3 as this added language provides no additional reliability benefit.

BAL-005-2 R4 and R6 appear to be duplicative with R2 in the draft version of TOP-010-1. Reporting ACE and the inputs to it are obviously Real-time data necessary to perform Real-time monitoring of the BES. LG&E/KU recommend that R4 and R6 be removed from the BAL-005-2 standard and allow TOP-010-1 R2 to be the single Balancing Authority requirement addressing implementation of an Operating Process or Procedure for Real-time data (which includes Reporting ACE and the scan rate data used to calculate Reporting ACE) quality issues.

The VRF for R5 is listed as “Medium.” This appears to be an administrative function to calculate an entities prior year performance and should be assigned a VRF of “Lower.”

Likes 0	
Dislikes 0	

Response

R3: Thank you for your comment. The SDT does not agree that being available for the calculation of Reporting ACE is the same as requiring Reporting ACE to be calculated. The SDT does not agree that R5 and R3 are linked in any way. Your interpretation would require the system used to calculate Reporting ACE to be available 99.95% of the time instead of the 99.5% defined in R5.

R4 & R6: Thank you for your comment. BAL-005-1 appears to be on a faster timeline than TOP-010-1. If your suggestion is implemented and BAL-005-2 is approved sooner than TOP-010-1, then there will be an interval without any requirement for an operating process or data quality indication in the NERC standards. This situation would not be acceptable. The SDT defers to NERC staff for coordination associated with the implementation timing of these standards.

VFR for R5: Thank you for your comment. The SDT does not agree with your assessment. Reporting ACE is necessary to ensure reliability and should be calculated continuously and therefore should have a VRF of Medium.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	
Document Name	
Comment	

Tacoma Power assumes that the intent of Requriement R3, Part 3.1, is that the total complement of frequency metering equipment meets the availability specification. For example, if one frequency metering equipment has an availability of 99.94%, but there is another frequency metering equipment available as a fail-over source such that availability of the redundant sources together is equal to or higher than 99.95%, this should be considered compliant. Is this assumption reasonable?

Could the drafting team please clarify how compliance with Requirement R3, Part 3.2, would be addressed if a Balancing Authority periodically tests frequency metering equipment (e.g., annually) and finds that the equipment has fallen out of calibration since the last test? For example, in the case of analog frequency transducers, in particular, the accuracy could stray over time. If a Balancing Authority tests its frequency metering equipment periodically and discovers that the accuracy is now less than 0.001 Hz, the Balancing Authority should not be in violation, since, in this scenario, it is not reasonable for them to have identifed the inaccuracy before the frequency metering equipment went out of calibration.

Tacoma Power assumes that the intent of Requirement R7, Parts 7.1 and 7.2, is not to address the real-time status of common sources, for either scan rate values or hourly megawatt-hour values, or for loss of time synchronization. It seems that these real-time issues would be addressed under Requirement R2, Requirement R6, and/or other requirements and would not necessarily constitute a violation of Requirement R7.

Likes 0	
Dislikes 0	

Response

R3.1: Thank you for your comment. The SDT agrees with your assessment that the 99.95% availability would be met with appropriate frequency metering redundancy.

R3.2: Thank you for your comment. The SDT agrees with your assessment of discovering that metering equipment accuracy has fallen out of adequate accuracy, assuming that the redundant frequency metering is used to replace the out of compliance metering as soon as it is discovered.

R7: Thank you for your comment. The SDT agrees with your interpretation.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R	
Answer	
Document Name	
Comment	

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provide such services and register with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) perform its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that’s the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

CO-1 recommend the following wording for R3:

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE:

3.1 that is available a minimum of 99.95% for each calendar year

3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz.

3.3 checked for accuracy once each calendar year

There was concerns about what quality the ± 0.001 Hz was being applied to.

In the definition of Actual Net Interchange, strike the last sentence since it is too prescriptive. We believe a BA should have the flexibility to either include or exclude the actual transfers across DC tie lines based on the modeling of the facility.

Likes 0	
Dislikes 0	

Response

General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R1: Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct.

R3: Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written.

Actual Net Interchange: Thank you for your comment. The SDT decided that the inclusion of asynchronous DC tie lines in ACE will result in ACE errors without offsetting benefits.

William Temple - William Temple

Answer	

Document Name	

Comment

PJM proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change.

Additionally, if this standard is to remain, then the name of the standard should be changed. It is now referred to as **Balancing Authority Control,** but the requirements are for **ACE Process Design**. BA Control is addressed by BAL requirements - not by this standard.

REQUIREMENT 2

This requirement is not a reliability-based standard and is not needed. R2 addresses reporting the loss of ACE to an RC. The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE, then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue - not a reliability issue.

It is a good practice that when a BA control center is not functional that it tells the RC, but this is covered elsewhere. IRO-005-3.1a R1.6 requires the RC monitor "Current ACE for all its Balancing Authorities. "

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? PJM suggests that frequency meter accuracy be included in the certification process.

Average availability (R3.1) on the other hand creates a reliability gap, and that as written does not increase reliability. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time.

If an availability requirement is needed, then we suggest tie it into the same time frame as the loss of ACE mandate.

There are two concerns with the way R3 is worded:

a. With the way R3 reads, it could be misinterpreted that the frequency metering equipment requires an accuracy of 0.001 Hz for 99.95% of the calendar year. That would mean checking (and fixing) your frequency metering device every hour to ensure you do not exceed four hours during a year with a frequency accuracy less than 0.001 Hz. This is not intent of R3 and the requirement should be rewritten. The intent is that the frequency metering equipment is *designed* to have a minimum accuracy of 0.001 Hz.

b. R3 could also be misinterpreted to mean that a BA's frequency error over an entire year must be 0.001 HZ or less.

PJM believes the requirement should be removed. However if the requirement is not removed PJM submits the following re-wording of R3 for clarity:

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE:

3.1 that is available a minimum of 99.95% for each calendar year

3.2 that is rated to, and has a metering accuracy with a precision to ± 0.001 Hz.

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process." Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

Requirement R6 is confusing regarding the term "errors." Are these metering errors such as spikes? Are these Inadvertent Interchange metering errors? The requirement should provide more clarity on this.

The term "scan-rate" should be changed to "scan rate." Nowhere else in the standard or the NERC glossary is this term hyphenated.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

PJM notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.

R7 requires the BAs to have a common source. This could possibly pose a conflict with CIP-005-5 R1, which could be interpreted to require a Responsible Entity to have individual access to a meter.

In R7, the word Tie-Line is not defined. In the NERC Glossary it is listed as “Tie Line.”

In R7.2, PJM’s concern here is that errors would be apparent in many more ways (and much more quickly) than by calculating hourly megawatt-hour values. This doesn’t appear to be a reliability requirement.

Likes 0	
Dislikes 0	

Response

Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed. The SDT believes the current name is more reflective of the standard.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

R2: Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC.

R3: Thank you for your comment. The SDT is more concerned about the accuracy than the rating of the equipment. Rating of the equipment does not necessarily guarantee the accuracy of the equipment.

R6: Thank you for your comment. The SDT is unclear about your observation and therefore has no suggested change. The SDT will change “scan-rate” to “scan rate”.

R7: Thank you for your comment. New tie lines and tie line metering are being added and modified on an ongoing basis. This is more than a design requirement; it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1. “Tie Line” is the term used within the Glossary of terms and the SDT will make the change.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

We continue to disagree with the majority of the requirements in the standard that stipulate the capabilities that a BA must have in order to perform its reliability tasks. In our view, these are more suited for inclusion in the Organization Certification Requirements as opposed to in Reliability Standards. The ongoing process to ensure accuracy of operating information and tools is an essential component of any operating entity which provides such services and registers with NERC as the responsible entity for complying with applicable Reliability Standards. To have explicit requirements for having accuracy metering data at specific scan rate and availability (R1, R3 and R5), flagging missing or invalid data (R4), having a process in place to detect and mitigate inaccurate or missing information (R6), and using common source information between adjacent BAs (R7) are the fundamental organization requirements to enable a BA (and any operating entity) performs its reliability tasks to meet its basic obligations.

If arguments are made to have these requirements specifically stipulated, then such argument can be extended to include every data and tool that an operating entity (including RC, TOP and GOP) uses to perform all of its tasks. If that's the case, there will be no end to the scope of this extension as this may include such data as PMU data, RTU data, voltage, current, MW, Mvar, frequency, etc., and tools such as on-line contingency analysis, EMS programs, line loading estimators, load flow programs, dynamic simulation software, etc. For years, operating entities have been relying on these data and tools to perform their tasks, and there have not been any notable events that occurred due to inaccurate data or tool capability.

We therefore once again urge the drafting team to consider retiring Requirements R1, R3, R4, R5 and R7 from BAL-005, and map them into Organization Certification Requirements. While argument can be made to retain R6 as it drives the proper behavior to ensure data errors are detected and mitigated, consideration may be given to also include this in the Organization Certification Requirements.

If for any reasons Requirement R3 is retained, then we would suggest rewording it to improve clarity. As written, R3 can be interpreted as a continuous accuracy requirement of 0.001 Hz under all conditions including use of secondary or tertiary backup equipment when necessary under certain conditions. We do not believe this is the intent of the requirement so it needs to be re-worded to not imply a continuous accuracy requirement. If the intent is to use primary frequency metering equipment that has demonstrated or been tested to meet the 0.001 Hz accuracy requirement, then the requirement and/or the measure should be revised to clearly indicate this is the objective/intent.

Likes 0	

Dislikes 0	
Response	

General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R1: Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct.

R3: Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written.

Actual Net Interchange: Thank you for your comment. The SDT decided that the inclusion of asynchronous DC tie lines in ACE will result in ACE errors without offsetting benefits.

John Fontenot - Bryan Texas Utilities - 1

Answer	
Document Name	
Comment	

na

Likes 0	
Dislikes 0	
Response	

Jeri Freimuth - APS - Arizona Public Service Co. - 3

Answer	
Document Name	
Comment	

1. Although it can be viewed as a "resource", maintaining Interchange obligations is a unique enough task for a Balancing Authority to perform, APS recommends leaving Interchange in as part of the Balancing Authority definition. "…maintains Demand and resource balance within a Balancing Authority Area, while maintaining Interchange obligations, and supports Interconnection frequency in real time."

2. The wording of R7.2 appears to be combining two requirements. The requirement to have a time-synchronized common source and to agree upon the hourly megawatt-hour values the source provides. These should be separated out as the current verbiage is unclear.

Likes 0	
Dislikes 0	

Response

1. Thank you for your comment. The SDT chose to eliminate interchange because it is included in resources.

2. Thank you for your comment. The SDT modified Requirement R7 Part 7.2 to clarify the intent. The SDT believes Requirement R7 Part 7.2 does not have two requirements. The SDT believes the requirement that you have suggested should be a separate requirement for compliance purposes would be part of the Operating Process as developed in Requirement R6. "Agreed upon" is necessary to aid in the identification of errors and assignment of the errors to the appropriate BA for mitigation as necessary under the Operating Process developed in Requirement R6.

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. – 3

Answer	
Document Name	

Comment

- The proposed version of BAL-005 is inconsistent with the recommendations of the Independent Experts Review Project and the Results-Based Reliability Standard Development Guidance.
- R1, R3, and R7 are design parameters and should be moved to a Guideline (and reviewed as part of a BA Certification). They are not performance-based, risk-based, or competency-based requirements.
- R4 seems to overlap the proposed TOP-010-1 R2 creating a potentially double-jeopardy."

Likes 0	

Dislikes 0	

Response

General: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R1, R3 & R7: Thank you for your comment. The SDT does not agree with your position that, once certified, a BA will maintain these systems without degradation since they are subject to continual modification.

R4: Thank you for your comment. BAL-005-1 appears to be on a faster timeline than TOP-010-1. If your suggestion is implemented and BAL-005-2 is approved sooner than TOP-010-1, then there will be an interval without any requirement for an operating process or data quality indication in the NERC standards. This situation would not be acceptable. The SDT defers to NERC staff for coordination associated with the implementation timing of these standards.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern suggests adding the below wording to the definition of Balancing Authority:

The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, while maintaining scheduled interchange and supporting Interconnection frequency in real time.

Southern Suggests adding the below wording to R1 and M1:

R1. The Balancing Authority shall use a design scan rate not greater than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate not greater than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Likes 0	

Dislikes 0	
Response	

Balancing Authority: Thank you for your comment. The SDT is of the opinion that your suggested wording is equivalent to the requirement as written, so no change is currently necessary.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons:

REQUIREMENT 1

The new R1 is a design requirement and not something that is subject to change

Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard.

REQUIREMENT 2

This requirement is not a reliability based standard and is not needed.

R2 addresses reporting the loss of ACE to an RC.

The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE?

It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."?

REQUIREMENT 3

The requirement defines (frequency) equipment accuracy and availability.

Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process.

Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time!

If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 4

Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes "invalid data" and defines "quality" (if the BA is to flag quality then the term should be defined somewhere)

REQUIREMENT 5

Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate?

REQUIREMENT 6

Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process" Is it more important to have a process that can address every cause of every scanning error? Is it even possible?

On the other hand, it is possible to have a process to handle no ACE values.

REQUIREMENT 7

R7 is a design requirement and not something that is subject to change.

The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term “time synchronized” from the requirement.

Likes 0	
Dislikes 0	

Response

Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

R2: Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC.

R3: Thank you for your comment. History has demonstrated that frequency measurement devices can and do deviate from specification and require recalibration or replacement. It would be foolish to assume that once certified they no longer need to be addressed.

R4: Thank you for your comment. Invalid data and data quality flags have been used in EMS since they were first developed. The SDT does not think these terms require definition.

R5: Thank you for your comment. Since CPS1 is based upon annual average ACE performance and is the primary measure of control compliance, it makes sense to require availability over the same or a similar time period to support that measure.

R6: Thank you for your comment. The Operating Process is not defined in the requirement. Any appropriate process that manages errors in ACE and the data to support the calculation of ACE will be acceptable. However, a process that handles every scan error may deviate from the principles of good quality control and result in detrimental tampering with the system.

R7: Thank you for your comment. New tie lines and tie line metering is being added and modified on an ongoing basis. This is more than a design requirement, it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1.

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC	
Answer	
Document Name	

Comment

We suggest the Standard be completely revisited to be:

R1. Each BA shall support Interconnection frequency through monitoring Reporting ACE

R2. A Balancing Authority shall maintain adequate metering, communications, and control equipment to prevent becoming a Burden on the Interconnection or other Balancing Authority Areas.

Likes 0	
Dislikes 0	

Response

R1 &R2: Thank you for your comment. The SDT believes the suggestion would result in a standard with undefined and unauditable requirements which could negatively impact reliability.

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	
Document Name	

Comment
The SRC proposes that BAL-005 be translated into a certification requirement for the following reasons: REQUIREMENT 1 The new R1 is a design requirement and not something that is subject to change Also, if this standard is to remain then the name of the standard should be changed. It is now referred to as **Balancing Area Control** but the requirements are for **ACE Process Design**. BA Control is addressed by BAAL requirements not by this standard. REQUIREMENT 2 This requirement is not a reliability based standard and is not needed. R2 addresses reporting the loss of ACE to an RC. The rationale states this is important to the RC as it relates to reliability. ACE has only a few moving parts (frequency, NET tie flow and NET Interchange). If a BA can't compute its own ACE then one of those three quantiles is unavailable. The RC does not rely on the BA for frequency. NET tie flow is not used in any reliability studies (whereas individual tie flows would come from the TO) and NET Interchange is a market issue not a reliability issue. Why then should the BA be mandated to tell the RC that it can't calculate ACE? It is a good idea that when a BA control center is not functional that it tells the RC but isn't that fact covered elsewhere, such as IRO-005-3.1a R1.6 mandating that the RC monitor "Current ACE for all its Balancing Authorities."? REQUIREMENT 3 The requirement defines (frequency) equipment accuracy and availability. Establishing minimum limits on meter accuracy (R3.2) can be rationalized, but is there a need to make this an auditable requirement? The SRC would suggest that frequency meter accuracy is better left to a certification process. Average availability (R3.1) on the other hand creates a realibilty gap, and that as written is a make work requirement. Every lost scan must be saved and summed over a year. Use of average availability is a good spot check for a Functional Entity to use in making

maintenance decisions, but as a standard use of average availability could be seen as establishing a reliability gap since some could even say this is not a good use of computer time! If an availability mandate is needed, then why not tie it into the same time frame as the loss of ACE mandate? REQUIREMENT 4 Requirement 4 is a fill-in-the-blanks standard unless the SDT defines what constitutes "invalid data" and defines "quality" (if the BA is to flag quality then the term should be defined somewhere) REQUIREMENT 5 Requirement 5 like Requirement 3.1 mandates an average availability. The concern that should be raised is that of mandating an average availability value. If a BA has 100% availability it can stop calculating ACE for the entire last day of the year and still be compliant! Average availability is a make work requirement. Every lost scan must be saved and summed over a year. If one were inclined to want an availability mandate then why not tie it into the same time frame as the loss of ACE mandate? REQUIREMENT 6 Requirement 6 would seem to be misplaced. R6 requires the BA to have a process for "correcting errors in the scanning process" Is it more important to have a process that can address every cause of every scanning error? Is it even possible? On the other hand, it is possible to have a process to handle no ACE values. REQUIREMENT 7 R7 is a design requirement and not something that is subject to change. The SRC notes that not all tie lines have time-synchronized meters. Adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.	
Likes 0	
Dislikes 0	
Response	

Standard Name: Thank you for your comment. The SDT chose the new name for the standard. This is the first suggestion that it be changed.

R1: Thank you for your comment. In the early days of EMS development, it was common practice to extend the scan rate to manage additional data or calculations. A six second design does not guarantee a six second scan rate for the life of the EMS.

R2: Thank you for your comment. The transmission of an ACE value to the Reliability Coordinator does not guarantee that the Reliability Coordinator will be aware of the loss of the ability to calculate ACE when that occurs. This requirement assures that that information is available to the RC.

R3: Thank you for your comment. History has demonstrated that frequency measurement devices can and do deviate from specification and require recalibration or replacement. It would be unwise to assume that once certified they no longer need to be addressed.

R4: Thank you for your comment. Invalid data and data quality flags have been used in EMSs since they were first developed. The SDT does not think these terms require definition.

R5: Thank you for your comment. Since CPS1 is based upon annual average ACE performance and is the primary measure of control compliance, it makes sense to require availability over the same or a similar time period to support that measure.

R6: Thank you for your comment. The Operating Process is not defined in the requirement. Any appropriate process that manages errors in ACE and the data to support the calculation of ACE will be acceptable. However, a process that handles every scan error may deviate from the principles of good quality control and result in detrimental tampering with the system.

R7: Thank you for your comment. New tie lines and tie line metering is being added and modified on an ongoing basis. This is more than a design requirement, it requires that the metering and metering methods be maintained on an ongoing basis. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain. The requirement for a common source has not been changed from the previous version of the standard, BAL-005-0.2b R12.1.

Kelly Dash - Kelly Dash, Group Name Con Edison	
Answer	
Document Name	
Comment	

R1 from BAL-005-0.2b should be retained in BAL-005-1 and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Likes 0	
Dislikes 0	

Response

R1: Thank you for your comment. The suggested R1 would be hard to enforce because there is no requirement that a BA be informed of new or modified generation or transmission within its boundaries. This is the problem that the SDT is attempting to correct.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	

Comment

R7.2 Not all tie lines have time-synchronized meters. The adjacent BAs just need to operate to common real time meters. The same integrated value for the hour should be transmitted to both BAs at the end of each hour. Remove the term "time synchronized" from the requirement.

Likes 0	
Dislikes 0	

Response

R7: Thank you for your comment. If the meters used for determining MWh values are not time synchronized, then the Operating Process required in R6 would not be valid. Time synchronization is intended to include all forms, such as accumulator freeze pulses, and not to require a specific time synchronizing mechanism. As long as some BAs have time synchronized metering for accumulated MWh this requirement should remain.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

SRP appreciates the efforts of the SDT and provides the following comments regarding the changes to BAL-005-1:

· R3 is vague and has the potential for inconsistent implementation as worded.

It is unclear whether the 99.95% availability calculation is to be applied independently to each individual metering point, or whether it should be the average availability of all metering equipment.

· R4 – SRP recommends reducing ambiguity by adjusting the requirement to state “System Operator”.

· R5 – SRP recommends providing clarification on how the 99.5% is to be calculated?

· R6 – SRP recommends rewording the standard to avoid creating the super tem “Balancing Authority Interconnection.

Likes 0	
Dislikes 0	

Response

R3: Thank you for your comment. The 99.95% only applies to the frequency metering.

R4: Thank you for your comment. If the term is changed as you suggest, it would require the BA to make ACE available to all System Operators (Generation, Transmission, and Reliability Coordinators) within their BA. This goes far beyond the intent of the requirement.

R5: Thank you for your comment. Different methods of determining the 99.5% availability may be appropriate for different EMS and different BAs.

R6: Thank you for your comment. As written the SDT is using two separate defined terms not creating a “super term”.

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment	
Provided in ACES Comments	
Likes 0	
Dislikes 0	
Response	

3. If you are not in support of the retirement of BAL-006-2 and the development of a guideline, please provide your objection(s) and proposed solution(s) in the area below.

John Fontenot - Bryan Texas Utilities - 1	
Answer	
Document Name	
Comment	
na	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP is in support of retiring BAL-006-2	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee	
Answer	

Document Name	
Comment	
The SRC supports the retirement of BAL-006-2.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the IRC SRC in supporting the retirement of BAL-006.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern supports the retirement of BAL-006-2. However, we suggest requirements be included in a commercial alternative arrangement, such as a NAESB standard, rather than a guideline that only suggests approaches and behaviors and is not binding or mandatory.	

Likes 0	
Dislikes 0	

Response

Thank you for your support. The drafting team considered the NAESB alternative, however, since the information process is currently under the NERC OC subcommittee RS, we felt it was more seamless to maintain it under a guideline.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy supports the retirement of BAL-006-2 in conjunction with the changes in BAL-005 as well as the development of the Guideline document as an integrated package. We feel that implementation of just one of these suggestions, without the others, would not sufficiently maintain reliability concerns with the grid.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

William Temple - William Temple

Answer	
Document Name	

Comment

PJM supports the retirement of BAL-006.

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R	
Answer	
Document Name	
Comment	
We support the retirement of BAL-006-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
: LG&E/KU would like to support the retirement of BAL-006 but as of now have questions regarding the guideline and implementation plan. For example, in the transition to a guideline, must existing inadvertent balances be minimized or do existing balances simply disappear?	
Likes 0	

Dislikes 0	
Response	
Thank you for your support. Since the balances are more commercial and have no impact on past reliability, the drafting team feels these are financial issues that could be resolved through standard business means.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In the BAL-005-1 Implementation Plan there is a reference to retirement of BAL-006-2 under "General Considerations" but further down there is a reference to BAL-006-2 Requirement 3 under "Retirements". Additionally, there is no reference to BAL-006-2 in the "Requested Retirement" section. Which is correct? Additionally, the BAL-005-1 Implementation Plan lacks clarity on effective dates for the Standards and definitions in question. BAL-001-2 is effective July 1, 2016. There may not be an approval on definitions contained within BAL-005-1 before that time period. Additionally the SDT is unclear if the definitions would apply to BAL-005-0.2b, which could still be in effect after BAL-001-2 is in effect but before BAL-005-1 becomes effective. A CEA will have to evaluate the Standards and definitions that are FERC approved, not proposed, for compliance monitoring efforts.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made clarifying modifications to the Implementation Plan for BAL-005-1 based on the information supplied in the retirement section. The SDT intends to file the proposed modifications prior to July 1, 2016 in compliance with the FERC directive. In addition, the proposed modification to the Reporting ACE definition incorporating thee ATEC term has no impact on reliability since the WECC Regional Standard includes the ATEC definition.	
Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
We agree with the SDT in proposing to retire BAL-006-2 and to develop an Inadvertent Interchange Guideline that will be approved by the NERC Operating Committee at a later date.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA agrees that BAL-006-2 is an energy accounting standard and not a Reliability Standard. However, guidelines are not enforceable. BPA agrees it is important to maintain requirements to calculate and account for Inadvertent Interchange. BPA proposes adding inadvertent accounting via a NAESB standard or business practice since the **NAESB** WEQ Inadvertent Interchange Payback Standards **already handles certain aspects of Interchange accounting.**	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. The drafting team considered the NAESB alternative, however, since the information process is currently under the NERC OC subcommittee RS, we felt it was more seamless to maintain it under a guideline.	

4. If you are not in support of the proposed modifications to FAC-001-3, please provide your objection(s) and proposed solution(s) in the area below.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We agree with the removal of the LSE function.

(2) However, we disagree with other proposed modifications in FAC-001-3. It was determined through the Paragraph 81 project that having Facilities within a BA's metered area boundaries are administrative and unnecessary. We suggest removing Requirement R3, part 3.3 and Requirement R4, part 4.3. These are administrative requirements that are not necessary for reliability. Furthermore, the NERC Rules of Procedure Section 501.4.4 already requires NERC to "ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority." There are equally efficient means that are already in effect; therefore, the SDT should remove these requirements, as they are unnecessary.

(3) We recommend extending the implementation plan to 36 months. The proposed 12-month implementation plan is insufficient because interconnection study requests can take as long as 18 months. These could take significant amounts of time if complex issues are encountered during negotiations of interconnection agreements.

(4) We thank the SDT for the opportunity to comment on this standard.

The Drafting Team respectfully disagrees that having Facilities within the metered boundaries of a Balancing Authority Area is administrative in nature. Generation operating outside the boundaries of any Balancing Authority must, itself, become a Balancing Authority by definition. Otherwise, it is detrimental to the Bulk Electric System by influencing Frequency with a source unknown to the rest of the Interconnection and the Reliability Coordinator. NERC requires all Facilities within the interconnected network to be within a Balancing Authority Area when they are being placed in service. Therefore, the Transmission Operator and the Balancing Authority must be informed by the asset owner and a Standard Interconnection Agreement signed prior to any operation (commercial or otherwise).

The Implementation Plan determines when you must have these procedures in place, not how long you have to conclude your interconnection study request. The proposed changes only require the addition of procedures to confirm the entity is within the metered boundaries of a Balancing Authority. That would have no impact on the duration of an interconnection study since the studies do not consider who the BAA is for a facility.

Likes 0	
Dislikes 0	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP, Group Name SPP Standards Review Group

Answer	
Document Name	

Comment

Its not that we aren't in support of the modifications to FAC-001 however, we have a concern that the documentation mentioned in Rationale 3.3 and 4.3 (Functional Model) isn't currently up to date. We would suggest to the drafting team to verify the latest review of this documentation. Also, we would suggest the drafting team verifying that this document is properly aligned with other documentation such as: The Rules of Procedure (ROP), Glossary of Terms and The Federal Power Act for consistency and reliability of the BES. Additionally, we would like for the drafting team to review the concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA in association referenced to BAL-005-0.2b Requirement R1 parts R1.1, R1.2 and R1.3. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

There currently is a separate active NERC project to align terms in the ROP and Glossary of Terms. It is outside the purview of this team to align terms between these documents. This Drafting Team contains members from both projects in an effort to help correct any incongruence. The Drafting Team believes the Rationale boxes adequately explain that Transmission Owners are not necessarily Balancing Authorities and, therefore, these roles must be defined and fulfilled prior to operations.

You are correct that these requirements align with those from BAL-005-0.2b. These requirements were relocated from that standard as part of this project. Therefore they will not be duplicative as they are replacing them.

Although the process to confirm that all Facilities reside within the metered boundaries of a BAA will use administrative means to be accomplished and evidenced, it does not take away from the importance of confirming that such relationships exists prior to operation.

Likes 0	
Dislikes 0	

Joel Wise - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

While TVA supports the intent of addressing the metered boundaries of the Balancing Authority Area in FAC-001-3, we believe the language of R3, part 3.3, and R4, part 4.3, needs to be improved. We recommend that wording similar to that used in the rationale statements be used in the requirement sub-parts as follows:

R3, part 3.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

R4, part 4.3: Procedures for confirming that the party seeking a new or materially modified interconnection has made appropriate provisions with a Balancing Authority to operate within that Balancing Authority Area's metered boundary.

As currently written in Draft 2, R3, part 3.3, appears to focus on "transmission Facilities" and ignores generation Facility and end-user Facility connections. Similarly, R4, part 4.3, appears to focus on "generation Facilities" and ignores transmission Facility and end-user Facility connections.

R3.3

The drafting team has made conforming modifications to Requirement R3.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R3.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "transmission," Requirement R3.3 more clearly reflects the fact that a Transmission Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

R4.3

The drafting team has made conforming modifications to Requirement R4.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R4.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "generation," Requirement R4.3 more clearly reflects the fact that a Generator Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

Likes 0	
Dislikes 0	

Jason Snodgrass - Georgia Transmission Corporation - 1	
Answer	
Document Name	
Comment	

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to "commissioning of a Facility" which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term "study" within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC's desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Since the requirements currently exist in BAL-005 and were not eliminated as part of P81, there is no debate that they are reliability based. The Drafting Team is proposing relocating them to FAC-001. Unfortunately, the TOP-003-3 data specification would not serve to confirm that a Facility is within the metered boundary of a BAA. Those data specifications are established to truly operate in real-time. The determination that a Facility is within the metered boundaries of a BAA must be determined prior to a new Facility operating. Although the determination that a Facility is within a BAA serves real-time operations, that does not preclude the confirmation of it occurring early than at that time. For example, Seasonal Studies are conducted to assure that proper planning occurs to allow for real-time operations. This confirmation of which BAA will have the Facility within its boundaries occurring during the planning and studying stage is appropriate too since reconciliation of concerns may need to be addressed with this entity.

Likes 0	
Dislikes 0	
Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1	
Answer	
Document Name	
Comment	

While the latest proposed revisions to FAC-001-3 are an improvement (by removing the unnecessary R5, R6 and R7), the additions of R3.3 and R4.3 could be better worded, are unnecessary as requirements (they attempt to address an energy accounting problem, not a reliability problem), and likely already included in most Facility Interconnection Requirements documents in the Metering and Telecommunications section under Guidelines and Technical Basis (created in the new FAC-001-2), and/or in interconnection agreements between Facility owners and transmission providers.

If the SDT chooses to retain these requirements, some changes in the wording are warranted: R3.2 reads, "Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections." In order to understand the sentence, it is helpful to make a substitution like the following: "Procedures for notifying [someone] of new [things]."

The new R3.3 reads: "Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries." A simple fix might be to change the word "of" to "that" so that it reads "Procedures for confirming with [someone] that new [things] are within a Balancing Authority Area's metered boundaries.".

The Drafting Team does not agree that each Facility being within the metered boundaries of a BAA is an energy accounting issue. If a Facility is not within a BAA, for example a generator, it can cause many reliability issues such as impacting Frequency and flows. This has occurred in the past, which proves the need for this requirement to remain.

Although this information may be included in some Interconnection Requirements, it is not mandated to be in all. If it is already included in those documents, then the entity will likely have little more to do.

Thank you for the suggested language to make the requirement read better. The SDT has made the modification as suggested.

Likes 0	
Dislikes 0	

Teresa Czyz - Georgia Transmission Corporation - 1,3 - SERC

Answer	
Document Name	

Comment

FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC-001 were removed including a requirement for metering and telecommunication.

Additionally, GTC understands that FAC-001 and FAC-002 are complimentary Standards in a sense that FAC-001 requires Transmission Owners or Generator Owners to define the interconnection requirements necessary to collect data from entities such that the Planning Coordinator and Transmission Planners can study the impact of interconnecting new or materially modified Facilities to the BES in accordance with FAC-002.

All of the requirements of FAC-001 are limited to the long-term planning time horizon. Based on the rationale and proposed language provided for R3.3 and R4.3, a new level of ambiguity has presented itself that could lead some to conclude that these interconnection requirements should be expanded beyond the planning horizon and lead up to "commissioning of a Facility" which resides in the operations horizon.

Based on the Ballot supporting material, the proposed FAC-001 R3.3 and R3.4 requirements were originally included in BAL-005-1. The goal of the requirement in BAL-005-1 was to ensure that Area Control Error is calculated properly. Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R3.3, R4.3) would violate paragraph 81 criteria and introduces ambiguity associated with the aforementioned planning horizon vs operations horizon concerns that is currently not addressed in FAC-001 or FAC-002. GTC believes this concern is already covered in operation horizon standards such as TOP-003-3 and IRO-010-2. Specifically, R4 of TOP-003-3 already addresses and requires the BA to distribute its data specification to entities that have data required by the BA analysis functions and Real-time monitoring. Additionally, R5 of TOP-003-3 requires each TOP, GO, GOP, TO, LSE, and DP to satisfy the obligations of the documented specifications.

In summary, GTC believes that the proposed requirements FAC-001-3-R3.3 and FAC-001-3-R4.3 address specific needs for operating the system and therefore belong in an Operations Standard which is already being covered in requirements of FERC approved TOP-003-3 which describes the information that TOs and GOs are required to provide to the Balancing Authority as specified by the Balancing Authority.

Therefore, GTC respectfully requests this drafting team to remove R3.3 and R4.3 as a proposed change to FAC-001-2 and further clarify the purpose statement of FAC-001 to resolve the ambiguity that this current draft introduced by clarifying the purpose of FAC-001 which should align with FAC-002 by inserting the term "study" within the purpose statement such as:

Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection study requirements available so that entities seeking to interconnect will provide the information necessary for studies conducted in accordance with FAC-002-2.

It is GTC's desire that the drafting team utilizes the justification provided by GTC to not move forward with the proposed R3.3 and R3.4 and a refer to TOP-003-3 to demonstrate that there is currently not a reliability gap and also take the time to clarify the purpose statement to resolve the ambiguity introduced with this revision which should not prevent the drafting teams goal of an approved ballot.

Since the requirements currently exist in BAL-005 and were not eliminated as part of P81, there is no debate that they are reliability based. The Drafting Team is proposing relocating them to FAC-001. Unfortunately, the TOP-003-3 data specification would not serve to confirm that a Facility is within the metered boundary of a BAA. Those data specifications are established to truly operate in real-time. The determination that a Facility is within the metered boundaries of a BAA must be determined prior to a new Facility operating.

Although the determination that a Facility is within a BAA serves real-time operations, that does not preclude the confirmation of it occurring early than at that time. For example, Seasonal Studies are conducted to assure that proper planning occurs to allow for real-time operations.   This confirmation of which BAA will have the Facility within its boundaries occurring during the planning and studying stage is appropriate too since reconciliation of concerns may need to be addressed with this entity.

Likes 0	
Dislikes 0	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no UI O&R

Answer	
Document Name	

Comment

The added requirements 3.3 and 4.3 are not clear. The drafting team copied R3.2 approach but it not work for 3.3. In R3.2 the Transmision Owner is notifying the other reliability entities that new or modified interconnection is being pursued. Technically that would include a notice to the BA. But an explicit sub-requirement is needed. Concerns with R3.3 are: 1. Use of word confirming. Confirming is beyond notification; a confirmation requires the TO to maintain the response from the BA and possibly go further and verify the BA is truthful. The SDT reply to the last comments indicated it was really concerned that the BA would not be aware of changes made by TO. 2. The use of phrase “those responsible for the reliability of affected systems” is not needed and should be replaced with ‘responsible Balancing Authority’ since that is the only reliability function implicated by this subrequirement. 3.The BA should be required to provide the procedure for notification from a TO when a new or modified interconnesction is being pursued. Then the TO can align its Interconnection requirements document to the BA process.

We do not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated “It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA’s metered boundaries”. We do not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read “Entity seeking to interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area’s metered boundaries”

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2.   FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

A Balancing Authority is not capable of knowing who *should* be requesting to be within its metered boundaries. However, the transmission owner must know and Facilities to which it is connected must have an Interconnection Agreement that identifies which Balancing Authority Area the connecting Facility is within. And, the Transmission Owner is responsible for notifying the Balancing Authority about the Agreement. This notification is essential for reliability reasons and system control considerations.

The SDT considered the option of placing the requirement in FAC-002 but found it more appropriate to transfer this knowledge during the interconnection process.

Likes 0	
Dislikes 0	

William Temple - William Temple	
Answer	
Document Name	
Comment	

PJM views FAC-001 as a reporting requirement that must be carefully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change." The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirement as part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility owner is required to register with NERC. PJM proposes that as part of that process, the facility owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entity(ies) that are involved.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

The idea of NERC having a registry is not without merit, but is outside the scope of this Drafting Team.

Likes 0	
Dislikes 0	

Shivaz Chopra - New York Power Authority - 6

Answer	
Document Name	

Comment

FAC-001-3. ***NYPA has a concern that R3.3 and 4.3 should be the responsibility of the interconnecting entity to ensure their facility is within a BA's metered boundary***.

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	

Dislikes 0

Dixie Wells - Lower Colorado River Authority - 5, Group Name LCRA Compliance

Answer

Document Name

Comment

The SDT should consider the impact of new requirements R3.3 and R4.3 in regions where a single BA exists. These requirements would not seem to apply in cases such as ERCOT, where clearly any TO or GO facility additions are within the one and only BA's metered boundaries.

Recommend the standard language additions:
3.3 In regions with multiple Balancing Authorities, procedures for confirming with those responsible for the reliability of affected systems of new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.

4.3 In regions with multiple Balancing Authorities, Procedures for confirming with those responsible for the reliability of affected systems of new or materially modified generation Facilities are within a Balancing Authority Area's metered boundaries.

The SDT agrees with your concern, but this consideration is addressed in the purpose of the requirement. The purpose of the requirement is to be certain that the entity has joined a BAA, regardless of the number of options available to them. Just because they can only join one BAA, does not mean that they did. As such, the SDT does not believe this conforming modification is necessary.

Likes 0

Dislikes 0

John Fontenot - Bryan Texas Utilities - 1

Answer

Document Name

Comment

na

Likes 0	
Dislikes 0	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy is not certain that the current language in R3.3 and R4.3 of the proposed FAC-001-3 adequately establishes that it is the responsibility of the interconnecting entity to make the necessary arrangements, and that the Transmission Owner is responsible for confirming with a Generator, who their Balancing Authority will be. We feel that this intent is clear from reading the Rationale for R3, but do not feel that this intent is ascertainable by reading R3.3 on its own. Duke Energy suggests the following revisions to R3.3 and R4.3 to add clarity:

R3.3: Procedures for confirming that new or materially modified transmission Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

R4.3: Procedures for confirming that new or materially modified generation Facilities are accurately telemetered, modeled, and accounted in Real-time systems of the Balancing Authority(s) designated by the interconnecting entity.

We feel that these modifications and the resulting modifications to the Guidelines and Technical Basis section of the standard, better illustrates the intent of the drafting team, without needing the requirements' rationale to decipher said intent.

Also, Duke Energy suggests a minor modification to language used in the sub-requirements of R3 and R4. We suggest the use of the term Procedure[s] with the [s] accompanying. This clears up ambiguity that could arise in the event that an entity only has one procedure that is applicable to these requirements.

The Drafting Team appreciates the feedback. The SDT recognizes that this is an issue in all NERC Reliability Standards. The Alignment of Terms SDT will be addressing this issue. For additional information please refer to Arizona Public Service comments and our associated response on pages 75 and 76 of this report.

The SDT contends that this not be limited to one and only one BA and the SDT recognizes that multiple BAs may be involved.

But the Drafting Team believes it is not reasonable or appropriate for the TO or applicable GO to assess how the BAA has incorporated "accurately" the entity into their BAA systems. Since all BAAs are certified, we can assume if the entity has an agreement for them to be in their BAA, that BAA has the ability to incorporate them into their systems appropriately.

Likes 0	
Dislikes 0	

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

APS agrees with the approach for Requirements R3.3 and R4.3, in that it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority, and that the Transmission Owner or Generation Owner is responsible for confirming that the party interconnecting to make appropriate arrangements with a Balancing Authority. Since Transmission Owners and Generation Owners may receive either transmission or generation interconnection requests, APS recommends revising the requirements as follows:

R3.3 – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries.

R4.3 – Procedures for confirming with **the associated Balancing Authority that the** new or materially modified **generation and/or** transmission Facilities, that those generation and/or transmission Facilities are within **its** metered boundaries.

R3.3

The drafting team has made conforming modifications to Requirement R3.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R3.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "transmission," Requirement R3.3 more clearly reflects the fact that a Transmission Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

R4.3

The drafting team has made conforming modifications to Requirement R4.3 to accurately reflect the intent of the drafting team, as described in the Rationale for R4.3. As stated in the Rationale, "it is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority *to ensure its Facilities are within the BA's metered boundaries*, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation." Additionally, the "Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries." By removing the term "generation," Requirement R4.3 more clearly reflects the fact that a Generator Owner properly addresses procedures for confirming that those responsible for reliability of the *applicable* affected systems are within a Balancing Authority Area's metered boundaries. This change promotes reliability because it ensures confirmation that all entities that affect reliability share relevant information because they are within a Balancing Authority Area's metered boundaries.

Likes 0	
Dislikes 0	

Anthony Jablonski - ReliabilityFirst - 10

Answer	

NERC

Document Name	
Comment	

ReliabilityFirst agrees the draft FAC-001-3 draft standard but offers the following comments for consideration.

1. **Requirement 3, Part 3.3**
   i. **Part 3.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified transmission Facility".**
2. **Requirement 4, Part 4.3**
   i. **Part 4.3 uses the term "materially modified". RF believes this term is ambiguous and requests the SDT further clarify what is considered a "materially modified generation Facility".**

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	

Jonathan Appelbaum - United Illuminating Co. - 1

Answer	
Document Name	
Comment	

1. R3.2 has the TO establishing a procedure to provide a notification whle R3.3 requires a confirmation. What is the difference in actions between notification and confirmation? Who or what is to be confirmed? The technical and guideline section should explain what the confirmation is supposed to be.

2. Do requirements R3.2 and R3.3 means the TO must perform this confirmation or can the procedure require the interconnecting party perform the confirmation? UI believes the TO establishes the procedure, or writes into its interconnection document the BA's process,

but the requirements document can require the interconnecting party to perform the notifiction and confirmation. If so, this should be added to the Technical Guideline section of Standard.

3. What is the purpose of R3.3 requiring a confrimation with " those responsible for the reliability of affected systems" instead of just stating the Balancing Authority. It should be the BA.

This is my proposed addition to Techincal Guideline section to address my comments 1 to 3:

"R3.2 requires the TO to establish a procedure to notify those responsible for the reliability of affected system(s) of new or materially modified existing interconnections. Notification means that the TO, requires either itself or the interconnecting party to contact the relevant reliability authorities and provide notice of the facility. R3.3 requires the TO to establish a procedure to confirm that a facility is within a metered boundary of a BA. Confirmation means that the TO, requires either itself or the interconnecting party to contact the BA and receive a letter of confirmation that the facility is in the BA metered boundary. The requirement and measure for R3 is only that the processes are established in the requirements document. The requirements document may reference a market or tariff as its process."

4. If proposed R3.3 was to be approved then it is missing the word "that". It should state: "Procedures for confirming with those responsible for the reliability of affected systems **that** new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries.."

The purpose of *confirmation* is to be certain that the information associated with the Facility has been transferred to the appropriate BA. The TO or applicable GO would not know who to "notify" until they have confirmed there is a BAA to notify.

Thank you for your language suggestions. The SDT has modified the requirement for clarity.   The Drafting Team does not prescribe how the applicable entity would draft their procedure[s] to accomplish the objective of confirming a BAA exists for the Facility. Each entity can decide how the outcome is achieved.

Likes 0	
Dislikes 0	

Douglas Webb - Douglas Webb

Answer	
Document Name	

Comment

KCP&L does not support the proposed revisions to FAC-001-3 R3.3 and recommends not adopting the Requirement. The proposed revised Standard is applicable to KCP&L as a registered Transmission Owner and, potentially, as a registered Generator Owner.

Requirement 3.3

R3.3 creates a compliance obligation for a disinterested party. The proposed R3.3, in effect, requires the Transmission Owner to create a procedure to promote the exchange of information between a third party Facility interconnecting with a Generator Owner whose facility is used to connect to the Transmission system. The procedure developed by the Transmission Owner must identify "affected systems," confirm who is responsible for reliability of the "affected systems," and, confirm with the "affected systems" owner that new interconnected facilities are within the metered boundaries of the identified Balancing Authority.

The difficulty with R3.3, as proposed, is evident when compliance scenarios are considered. For example, the Transmission Owner creates the required procedure under R3.3. The rationale—the compliance goal—for R3.3 centers on a duty by of the party interconnecting (PI) to make appropriate arrangements with the BA to ensure the PI Facilities are within the BA's metered boundaries. If the PI fails to fulfill its duty, it raises the question: Where is the noncompliance under R3.3? The Transmission Owner created the procedure, as required, yet, the stated rationale, goal, is not accomplished.

To achieve the stated rationale's goal, It would seem the compliance duty should fall to the party interconnecting. Absent that, the Balancing Authority and/or the Generator Owner whose facilities are used to interconnect to the transmission system would be in a better position to address Balancing Authority Area's metered boundaries. Also, the Requirement seems redundant since there are active NERC Standards requiring Generator Owners to inform Transmission Owners of changes to the GOs' facilities and Transmission Owners informing BA of new interconnections. Finally, from a practical viewpoint, it is just not likely a PI would connect without metering and SCADA connections—all such activity providing visibility to the BA and TO of changes to the system.

KCP&L recommends removing R3.3 or, in the alternative, suggests deleting "with those responsible for the reliability of affected systems of" from the proposed R3.3.

R3.3: "Procedures for confirming ~~with those responsible for the reliability of affected systems of~~ new or materially modified transmission Facilities are within a Balancing Authority Area's metered boundaries."

"Affected System"

Generally, defined terms better serve compliance with Standards and implementation of Requirements. The term, "affected system" is not defined. FERC approved *pro forma* interconnection agreements define the term as, "...an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection." KCP&L believes there may be benefit aligning the undefined NERC Standard terms relating to interconnection facilities with equivalent FERC *pro forma* interconnection agreements defined terms. While such an effort would require substantial effort to address all affected Standards, for the purposes of this Standard, we would encourage adopting FERC's *pro forma* definition for the proposed revision to FAC-001-3.

The SDT believes that the lack of confirmation would indicate their procedure inadequate.

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT supports the comments of the IRC SRC. The comments are provided below:

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

The idea of NERC having a registry is not without merit, but is outside the scope of this Drafting Team.

Likes 0	
Dislikes 0	

Joshua Eason - ISO New England, Inc. - NA - Not Applicable - NPCC

Answer	
Document Name	

Comment

This standard should not be a reliability standard, the contents of the standard do nothing to improve the reliability of the system.

The SDT disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. An example of how this could negatively impact reliability is when a generator that has not transferred the knowledge that it is within a BA and thus may have an impact on control and Frequency.

Likes 0	
Dislikes 0	

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities

Answer	
Document Name	

Comment

Exelon thinks R3 (and R4) needs to be re-written. We suggest:

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements for new or materially modified existing interconnections:

3.1. Procedures for coordinated studies of new or materially modified interconnections and impacts on affected system(s).

3.2. Procedures for notifying responsible entities of affected systems identified in part 3.1.

3.3. Procedures for confirming with responsible entities that that the new or modified Facilities are within a Balancing Authority Area's metered boundaries.

We also note that the phrase "materilaly modifed" may be subject to interpretation during an audit. The Guideline and Technical Basis section allows the use of engineering judgement when determing what is "material". It seems to beg the question, if an entity is using it's interconnection process and associated procedures as required by the Standrd, the change is material. Has the SDT considerd removing material from the language? This phrase is not defined or used in any other standard other than FAC-001 and 002. We believe either of these changes are non-substantive and would not require an additional comment period.

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC, Group Name ISO Standards Review Committee

Answer	
Document Name	

Comment

The SRC views FAC-001 as a reporting requirement that must be carfully drafted. The requirement must be crafted as an obligation that an owner incurs "when circumstances change". The obligation may be better addressed in a venue other than the reliability standards. One possibility would be to include the essence of the requirmentas part of the NERC registration process to avoid unnecessary compliance tracking.

Every facility own should be required to register with NERC. The SRC proposes that as part of that process the owners identify the RC area, BA area and TOP area that the facility will operate within. The registration would also mandate that whenever one or more of those areas change, then the owner must inform NERC of the change and also inform the entitiy(ies) that will be changed.

The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. A FAC-001-3 requirement to have verification of this will just lead to a paper exchange where TOPs, GOPs, and Loads will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. Keep in mind this includes each and every load, every piece of transmission, and every generator. This provides no reliability value.

"Materially modified" was used in Requirement R3.1, R3.2, R4.1, and R4.2 of the current standard and the SDT used the same language for consistency and felt since it was previously approved we believe that it is clear, from experience, that the industry understands the meaning.

Likes 0	
Dislikes 0	

Kelly Dash - Kelly Dash, Group Name Con Edison

Answer	
Document Name	

Comment

Requirement 3.3 and 4.3 should not be moved to FAC-001-3. The BA is in the best position to know its metered boundaries and confirm if any new or modified transmission or generation project is within those metered boundaries. The proposed R3.3 and R4.3 should remain in BAL-005, but be assigned to the BA. R1 from BAL-005-0.2b should be retained and re-written as follows:

"The Balancing Authority shall ensure that any new or modified generation or transmission operating within its Balancing Authority Area is included within its metered boundaries."

Alternatively the proposed R3.3 and R4.3 could be moved to FAC-002-2. FAC-002-2 is more appropriate than FAC-001-2 for this requirement because FAC-002-2 applies to TOs and GOs "seeking to interconnect" new or modified facilities. Therefore FAC-002-2 is more in line with the SDT's rationale that "It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries…"

The Interconnecting Party decides which BAA they are going to be within, not the BAA. A Balancing Authority is not capable of knowing who *should* be requesting to be within its metered boundaries, nor can they require someone to be inside their BAA. For reliability reasons, we must confirm they have transferred the knowledge to at least one BA. The Drafting Team believes this confirmation occurring as part of the Interconnection process is more appropriate than when the studies are occurring in FAC-002. The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

Glenn Pressler - CPS Energy - 1,3,5

Answer	
Document Name	

Comment

this needs work & here my support for the overall theme of comments submitted by MRO-NSRF, SCR, and also Oncor.

Thank you for your comment. Please refer to our responses to the entities mentioned above.

Likes 0	
Dislikes 0	

Jeremy Voll - Basin Electric Power Cooperative - 3

Answer	
Document Name	
Comment	

R3.3 and R4.3: The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

The Drafting Team disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

Likes 0	
Dislikes 0	

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	
Document Name	
Comment	

R3.3 and R4.3 The concept that all generation, transmission, and load must be within the metered bounds of a BA is a control area criteria that pre-dates the NERC standards. It is a concept that comes about by operating to common meters. It is therefore redundant and unnecessary to explicitly state that all facilities must be within a BA. The FAC-001-2 requirement to have verification of this will just lead to a paper exchange where TO, GO, will be asking BAs for pieces of documentation that they are within a given BA or to sign agreements that acknowledge the facility is within a BA. This provides no incremental reliability value. Recommend to remove this Requirement.

The Drafting Team disagrees that confirming all Facilities are within a BAA metered boundary does not improve the reliability of the system. It is a proven reliability risk that all Facilities must be within the metered boundaries of a BAA. If not, a Facility such as a generator could harm Frequency without any consequence. Although the implementation of confirming any new and modified facilities (not all existing equipment, as is mentioned in the comment) will take on an administrative nature, that does not diminish its importance in ensuring reliability because it provides added assurance that all facilities are taken into account in planning.

Likes 0	
Dislikes 0	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

SRP is in support of the proposed FAC-001-3

Thank you.

Likes 0	
Dislikes 0	

Tammy Porter - Tammy Porter

Answer	
Document Name	

Comment

Oncor does not support the proposed changes to R3. The SDT, in the rationale box states “the Transmission Owner is responsibile for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries”. Oncor does not believe that the Transmission Owner should be responsible for the compliance of the interconnecting Transmission Owner. Therefore, Oncor recommends changing R3.3 to the following: "3.3. Requirement that new or materially modified transmission Facilities of the interconnecting Transmission Owner are within a Balancing Authority Area's metered boundaries."

The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

Likes 0	
Dislikes 0	

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

Provided in ACES Comments

Likes 0	
Dislikes 0	

Louis Slade - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion does not support the proposed changes to R3 and R4. The SDT, in the rationale boxes stated “It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA’s metered boundaries”. Dominion does not believe it is appropriate to shift the compliance responsibility of one entity to another and therefore suggests the SDT also include Distribution Provider in the applicability section and then develop a requirement to read “Entity seeking to

interconnect (TO, GO or DP) shall confirm with those responsible for the reliability of affected systems that its newly installed or modified Facility is within a Balancing Authority Area's metered boundaries" The asset owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.	
Likes 0	
Dislikes 0	

End of Report

Standards Announcement Reminder

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Additional Ballots and Non-binding Polls Open through January 11, 2016

Now Available

Additional ballots for **BAL-005-1 – Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange** as well as non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for BAL-005-1 and FAC-001-3 are open through **8 p.m. Eastern, Monday, January 11, 2016.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and associated VRFs and VSLs by clicking here.

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 https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The results will be announced and posted to the project page when the ballots close. The drafting team will consider all comments received during the formal comment period and determine the next steps of the project**.**

Standards Development Process

For more information on the Standards Development Process, please 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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404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Formal Comment Period Open through January 11, 2016

Now Available

A formal comment period for **BAL-005-1 – Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange** is open through **8 p.m. Eastern, Monday, January 11, 201.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in these drafts of the standards.

Commenting

Use the electronic form to submit comments on the standards. 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.

If you are having difficulty accessing the Standards Balloting & Commenting System 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

An additional ballot for the three standards and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for FAC-001-3 will be conducted **December 31, 2015 through January 11, 2016.**

Standards Development Process

For more information on the Standards Development Process, please refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Ballot and Non-binding Poll Results

Now Available

A formal comment period and additional ballots for **BAL-005-1 –Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements,** a ballot for the recommended retirement of **BAL-006-2 – Inadvertent Interchange,** as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for BAL-005-1 and FAC-001-3 concluded **8 p.m. Eastern, Monday, January 11, 2016.**

The standards received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides detailed results for the ballots and non-binding polls.

	Ballot	Non-binding Poll
Standard	Quorum / Approval	Quorum / Supportive Opinions
BAL-005-1	84.13% / 70.64%	82.53% / 74.38%
FAC-001-3	83.17% / 75.54%	82.53% / 75.44%
BAL-006-2	84.44% / 94.30%	

Next Steps

The drafting team will consider all comments received during the formal comment period and determine the next steps of the project.

Standards Development Process

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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Atlanta, GA 30326
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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/38)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 IN 1 ST
Voting Start Date: 12/31/2015 12:01:00 AM
Voting End Date: 1/11/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 265
Total Ballot Pool: 315
Quorum: 84.13
Weighted Segment Value: 70.64

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	78	1	43	0.741	15	0.259	0	8	12
Segment: 2	10	0.9	4	0.4	5	0.5	0	0	1
Segment: 3	72	1	42	0.792	11	0.208	0	8	11
Segment: 4	25	1	16	0.889	2	0.111	0	2	5
Segment: 5	72	1	32	0.696	14	0.304	0	12	14
Segment: 6	44	1	24	0.727	9	0.273	1	5	5
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.2	1	0.1	1	0.1	0	0	0

9									
Segment: 10	8	0.8	5	0.5	3	0.3	0	0	0
Totals:	315	7	168	4.945	60	2.055	1	36	50

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments

1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party

					Comments
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted

1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		None	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	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		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
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		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	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		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A

3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A

3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	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	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern	Ramon Barany		Negative	Third-Party

	Indiana Public Service Co.				Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	N/A
3	Snohomish County	Mark Oens		Affirmative	N/A

	PUD No. 1				
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		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	Third-Party Comments
4	Austin Energy	Tina Garvey		Abstain	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	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		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	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		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy -	David Greyerbiehl		None	N/A

	Consumers Energy Company				
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Third-Party Comments
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	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	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Negative	Third-Party Comments
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	Third-Party Comments
5	NB Power Corporation	Rob Vance		Negative	Third-Party Comments
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A

5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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		None	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		Abstain	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	Brandy Spraker		Negative	Comments

	Authority				Submitted
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		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		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	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	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power	Chris Bridges	Douglas Webb	Affirmative	N/A

	and Light Co.				
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lower Colorado River Authority	Michael Shaw		None	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	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Third-Party Comments
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
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	Comments Submitted
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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	Third-Party Comments
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments

10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/38)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-006-2 IN 1 ST
Voting Start Date: 12/31/2015 12:01:00 AM
Voting End Date: 1/11/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 266
Total Ballot Pool: 315
Quorum: 84.44
Weighted Segment Value: 94.3

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	78	1	55	0.965	2	0.035	0	9	12
Segment: 2	10	1	8	0.8	2	0.2	0	0	0
Segment: 3	72	1	52	0.981	1	0.019	0	8	11
Segment: 4	25	1	16	1	0	0	0	4	5
Segment: 5	72	1	46	0.979	1	0.021	0	11	14
Segment: 6	44	1	32	0.97	1	0.03	1	5	5
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.2	1	0.1	1	0.1	0	0	0

9									
Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	315	7.1	219	6.695	8	0.405	1	38	49

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A

1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and	Mike ONeil		Affirmative	N/A

	Light Co.				
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		None	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento	Tim Kelley	Joe Tarantino	Affirmative	N/A

	Municipal Utility District				
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		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	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		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	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	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy	Steven Lancaster		Affirmative	N/A

	Services				
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		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Abstain	N/A

3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	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		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company -	R. Scott Moore		Affirmative	N/A

	Alabama Power Company				
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		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	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		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	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		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	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		Affirmative	N/A

5	AEP	Thomas Foltz		Abstain	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		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy	Mike Hirst		None	N/A

	Power Management, LLC				
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	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	Dixie Wells		Abstain	N/A

	Authority				
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	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		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities	Dan Wilson		None	N/A

	Corporation				
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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		None	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		Abstain	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	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		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 Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lower Colorado River	Michael Shaw		None	N/A

	Authority				
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		Affirmative	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		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	No Comment Submitted
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	Comments Submitted
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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	Third-Party Comments
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	David Greene		Affirmative	N/A

	Corporation				
10	Southwest Power Pool Regional Entity	Bob Reynolds		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

Survey: View Survey Results (/SurveyResults/Index/38)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 IN 1 ST
Voting Start Date: 12/31/2015 12:01:00 AM
Voting End Date: 1/11/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 262
Total Ballot Pool: 315
Quorum: 83.17
Weighted Segment Value: 75.54

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	78	1	44	0.721	17	0.279	0	4	13
Segment: 2	10	0.8	4	0.4	4	0.4	0	0	2
Segment: 3	72	1	45	0.763	14	0.237	0	1	12
Segment: 4	25	1	17	0.85	3	0.15	0	0	5
Segment: 5	72	1	42	0.764	13	0.236	0	3	14
Segment: 6	44	1	29	0.763	9	0.237	0	1	5
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment:	2	0.1	1	0.1	0	0	0	1	0

9									
Segment: 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals:	315	6.7	189	5.061	61	1.639	0	12	53

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments

1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Dairyland Power Cooperative	Robert Roddy		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	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	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A

1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy -	Mike ONeil		Negative	Comments

	Florida Power and Light Co.				Submitted
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Peak Reliability	Jared Shakespeare		None	N/A
1	PHI - Potomac Electric Power Co.	David Thorne		Affirmative	N/A
1	Platte River Power Authority	John Collins		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		None	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	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		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A

1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		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	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		None	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A

3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Third-Party Comments
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	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	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Comments Submitted

3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	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		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Kenneth Goldsmith		Negative	Third-Party Comments
4	Austin Energy	Tina Garvey		None	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	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		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	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		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy -	David Greyerbiehl		Affirmative	N/A

	Consumers Energy Company				
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Randi Heise		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	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		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Los Angeles	Kenneth Silver		Affirmative	N/A

	Department of Water and Power				
5	Lower Colorado River Authority	Dixie Wells		Negative	Comments Submitted
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	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	NB Power Corporation	Rob Vance		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power	Tyson Archie		Affirmative	N/A

	Authority				
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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		None	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		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	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	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		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	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	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	Comments Submitted
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		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted

6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Third-Party Comments
6	Lower Colorado River Authority	Michael Shaw		None	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	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Third-Party Comments
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
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		Affirmative	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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A

10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 315 of 315 entries

BALLOT RESULTS

Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 Non-binding Poll IN 1 NB
Voting Start Date: 12/31/2015 12:01:00 AM
Voting End Date: 1/11/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 222
Total Ballot Pool: 269
Quorum: 82.53
Weighted Segment Value: 74.38

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	68	1	31	0.721	12	0.279	0	15	10
Segment: 2	8	0.5	3	0.3	2	0.2	0	2	1
Segment: 3	63	1	28	0.757	9	0.243	0	14	12
Segment: 4	20	1	13	1	0	0	0	4	3
Segment: 5	60	1	21	0.7	9	0.3	0	17	13
Segment: 6	37	1	17	0.708	7	0.292	0	7	6
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	2	0.2	2	0.2	0	0	0	0	0

Segment: 10	8	0.6	4	0.4	2	0.2	0	2	0
Totals:	269	6.3	119	4.786	41	1.514	0	62	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		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power	Tony Kroskey		None	N/A

	Cooperative, Inc.				
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	Comments Submitted

1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Abstain	N/A

1	Peak Reliability	Jared Shakespeare		None	N/A
1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	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		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	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		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest	John Shaver		Negative	Comments

	Transmission Cooperative, Inc.				Submitted
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		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A

3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted

3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Abstain	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		Abstain	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted

3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	PNM Resources	Michael Mertz		None	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company -	R. Scott Moore		Affirmative	N/A

	Alabama Power Company				
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		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Abstain	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		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Abstain	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A

4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	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		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Abstain	N/A
5	Basin Electric Power Cooperative	Mike Kraft		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	Calpine Corporation	Hamid Zakery		None	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	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power	Harold Wyble	Douglas Webb	Affirmative	N/A

	and Light Co.				
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	Comments Submitted
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Lower Colorado River Authority	Dixie Wells		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	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	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	Comments Submitted

5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	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		None	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		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley	M Lee Thomas		None	N/A

	Authority				
5	Westar Energy	stephanie johnson		Abstain	N/A
5	Xcel Energy, Inc.	David Lemmons		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	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		Abstain	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	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		Negative	Comments Submitted
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
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	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 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		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		None	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	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		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	Comments Submitted
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 269 of 269 entries

BALLOT RESULTS

Survey: View Survey Results (/SurveyResults/Index/38)
Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 Non-binding Poll IN 1 NB
Voting Start Date: 12/31/2015 12:01:00 AM
Voting End Date: 1/11/2016 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 222
Total Ballot Pool: 269
Quorum: 82.53
Weighted Segment Value: 75.44

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	68	1	31	0.721	12	0.279	0	14	11
Segment: 2	8	0.5	4	0.4	1	0.1	0	2	1
Segment: 3	63	1	31	0.738	11	0.262	0	9	12
Segment: 4	20	1	13	0.929	1	0.071	0	3	3
Segment: 5	60	1	27	0.75	9	0.25	0	12	12
Segment: 6	37	1	17	0.68	8	0.32	0	6	6
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	1	0	0	0	0	0	0	1	0
Segment:	2	0.1	1	0.1	0	0	0	1	0

9									
Segment: 10	8	0.5	5	0.5	0	0	0	3	0
Totals:	269	6.1	129	4.818	42	1.282	0	51	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		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	Abstain	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power	Tony Kroskey		None	N/A

	Cooperative, Inc.				
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	Comments Submitted
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho	Laura Nelson		Affirmative	N/A

	Power Company				
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Negative	Comments Submitted
1	Peak Reliability	Jared Shakespeare		None	N/A

1	Platte River Power Authority	John Collins		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	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		Affirmative	N/A
1	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		None	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	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		Affirmative	N/A
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission	John Shaver		Negative	Comments Submitted

	Cooperative, Inc.				
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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	N/A
2	BC Hydro and Power Authority	Venkataramakrishnan Vinnakota		None	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Negative	Comments Submitted
2	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A

3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	Comments Submitted
3	BC Hydro and Power Authority	Faramarz Amjadi		Abstain	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove Springs	Mark Schultz		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted

3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A
3	JEA	Garry Baker		None	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted

3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Dana Wheelock		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company -	R. Scott Moore		Affirmative	N/A

	Alabama Power Company				
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		None	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	Turlock Irrigation District	James Ramos		None	N/A
3	Westar Energy	Bo Jones		Affirmative	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		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	DTE Energy - Detroit Edison Company	Daniel Herring		Abstain	N/A
4	FirstEnergy - Ohio Edison Company	Doug Hohlbaugh		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted

4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	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		None	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		Abstain	N/A
4	South Mississippi Electric Power Association	Steve McElhaney		None	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		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	Comments Submitted
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	Calpine Corporation	Hamid Zakery		None	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	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Abstain	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy -	Harold Wyble	Douglas Webb	Negative	Comments

	Kansas City Power and Light Co.				Submitted
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Abstain	N/A
5	Lower Colorado River Authority	Dixie Wells		Negative	Comments Submitted
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	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	Comments Submitted
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Wayne Sipperly		Negative	Comments Submitted
5	NextEra Energy	Allen Schriver		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power	Teresa Czyz		None	N/A

	Corporation				
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	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		None	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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	Tallahassee Electric (City of Tallahassee, FL)	Karen Webb		Affirmative	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A

5	Westar Energy	stephanie johnson		Affirmative	N/A
5	Xcel Energy, Inc.	David Lemmons		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Abstain	N/A
6	Bonneville Power Administration	Alex Spain		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	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		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lower Colorado River Authority	Michael Shaw		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and	Ryan Streck		Negative	Comments

	Water				Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	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		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
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	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		Abstain	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		Abstain	N/A
6	Tennessee Valley Authority	Marjorie Parsons		None	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Abstain	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Abstain	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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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

This is the final posting of the draft standard for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR Posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015
Standard posted for 45-day comment period and successive ballot	November 10, 2015

Anticipated Actions	Date
Final ballot	January – February 2016
NERC Board adoption	February 2016

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:

Rationale for Modification of AGC: The original definition of AGC reflects "how to" control and automatically adjust equipment in a Balancing Authority Area and does not reflect the current technology nor the evolution of the industry from a "Control Area" to a "Balancing Area". In addition, it was telling the entity "how to do it" rather than allowing the entity to perform the necessary functions in the most effective and reliable manner.

The new definition reflects a process and allows the entity the flexibility to perform the necessary function in the most effective and reliable manner to address such process without being instructed on "how to do it".

Automatic Generation Control (AGC): A process designed and used to automatically adjust a Balancing Authority Areas' Demand and/or resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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.

$$\mathbf{I}_{ATEC} = \frac{\mathrm{PII}_{accum}^{on/off\ peak}}{(1-Y)*H} \quad \text{when operating in Automatic Time Error Correction Mode.}$$

The absolute value of $\mathbf{I}_{ATEC}$ shall not exceed $\mathbf{L}_{max}$ **.**

$\mathbf{I}_{ATEC}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I}_{ATEC}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,
  where:

$$\mathrm{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \mathrm{PII}_{accum}^{on/offpeak} + \mathrm{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Rationale for Modification of Balancing Authority: The SDT has recommended to change the definition of Automatic Generation Control (AGC) and to be consistent, with the change to AGC, the SDT recommends changing the definition of a Balancing Authority. In addition, Project 2015-04 Alignment of Terms SDT brought to our attention of the inconsistent use of "load-interchange-generation" and through the Alignment of Terms project it was recommend a SDT associated with a BAL Standard address the issue. The proposed changes reflects a Balancing Authority.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

When this standard has received ballot approval, the text boxes will be moved to the Supplemental Material Section of the s*tandard.*

A. Introduction

1. **Title:** Balancing Authority Control
2. **Number:** BAL-005-1
3. **Purpose:** This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

A successful Operating Process must include the ability for hourly accumulated Tie Line MWH values to be agreed-upon between Balancing Authority Areas to aid in the identification errors and assign such errors to the appropriate Balancing Authority Areas for mitigation if necessary.

Instantaneous tie line flows between BAs cannot be effectively compared in real time. Methods to confirm accuracy of instantaneous metering is achieved through other means. The integration of instantaneous metered values is compared with accumulated MWh values to determine the accuracy of (error included in) the instantaneous metering for each BA. This comparison indicates the accuracy (amount of error) for each BA's own instantaneous metering as compared to its own accumulated MWh metering. However, it does not confirm that the accumulated MWh metering for one BA is equivalent to the accumulated MWh metering for the adjacent BA on the same tie line. This can only be confirmed by comparing the accumulated MWh value for one BA to the accumulated MWh value for the adjacent BA. If these two values are the same, any problem with the metering is identified by the difference between the integrated instantaneous MWhs and the accumulated MWh for that BA. However, if there is a difference between the accumulated MWhs between the two adjacent BAs, those BAs must agree upon a common value to use for that hour for that tie line in order to assign responsibility for managing the error represented by the difference between their accumulated values. If the BAs do not agree upon a value, the difference between the accumulated values will not be included in their error mitigation process and that error will therefore be passed to the interconnection as a frequency control burden.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the Tie Line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors

in the scan rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors under the Operating Process as developed in Requirement R6.

M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstrate a common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator within no more than 50 minutes from the beginning of the	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator with mo more than 55 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator with no more than 60 minutes from the beginning of an	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of a 30-minute inability to calculate Reporting ACE.

			inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	inability to calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan rate accuracy of data used in the calculation of Reporting ACE.
R7.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a common source for Tie Lines, Pseudo-ties and Dynamic

						Schedules with its Adjacent Balancing Authorities **Or** **The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking

0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	

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

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

This is the final posting of the draft standard for a 10-day final ballot.

Completed Actions	Date
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Standard posted for 45-day comment period and initial ballot	July 30, 2015
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   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority

Effective Date: See Implementation Plan for BAL-005-1

B. Requirements and Measures

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

R1. The Balancing Authority shall use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

R2. A Balancing Authority that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

R4. The Balancing Authority shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

A successful Operating Process must include the ability for hourly accumulated Tie Line MWH values to be agreed-upon between Balancing Authority Areas to aid in the identification errors and assign such errors to the appropriate Balancing Authority Areas for mitigation if necessary.

Instantaneous tie line flows between BAs cannot be effectively compared in real time. Methods to confirm accuracy of instantaneous metering is achieved through other means. The integration of instantaneous metered values is compared with accumulated MWh values to determine the accuracy of (error included in) the instantaneous metering for each BA. This comparison indicates the accuracy (amount of error) for each BA's own instantaneous metering as compared to its own accumulated MWh metering. However, it does not confirm that the accumulated MWh metering for one BA is equivalent to the accumulated MWh metering for the adjacent BA on the same tie line. This can only be confirmed by comparing the accumulated MWh value for one BA to the accumulated MWh value for the adjacent BA. If these two values are the same, any problem with the metering is identified by the difference between the integrated instantaneous MWhs and the accumulated MWh for that BA. However, if there is a difference between the accumulated MWhs between the two adjacent BAs, those BAs must agree upon a common value to use for that hour for that tie line in order to assign responsibility for managing the error represented by the difference between their accumulated values. If the BAs do not agree upon a value, the difference between the accumulated values will not be included in their error mitigation process and that error will therefore be passed to the interconnection as a frequency control burden.

R6. Each Balancing Authority that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the Tie Line~~tie line~~ megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan rate~~scan-rate~~ values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that each Tie Line~~Tie-Line~~, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

7.1. a common source to provide information to both Balancing Authorities for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors under the Operating Process as developed in Requirement R6.

M7. The Balancing Authority shall have dated evidence such as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that will be used to demonstrate a common source for the components used in the calculation of Reporting ACE with its Adjacent Balancing Authority.

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A	Balancing Authority was using a design scan rate of greater than six seconds to acquire the data necessary to calculate Reporting ACE.
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of a 30-minute~~the~~ inability to calculate Reporting ACE but notified its Reliability Coordinator within no more~~less~~ than ~~or equal to~~ 50 minutes from the beginning of the inability to	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of a 30-minute~~an~~ inability to calculate Reporting ACE but notified its Reliability Coordinator within~~in~~ n~~m~~o more~~less~~ than ~~or equal to~~ 55 minutes from the beginning of an inability to	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of a 30-minute~~an~~ inability to calculate Reporting ACE but notified its Reliability Coordinator within~~in~~ no more~~less~~ than ~~or equal to~~ 60 minutes from the beginning of an inability to	The Balancing Authority failed to notify its Reliability Coordinator within 60 minutes of the beginning of a 30-minute~~an~~ inability to calculate Reporting ACE.

			calculate Reporting ACE.	calculate Reporting ACE.	calculate Reporting ACE.	
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but was available greater than or equal to 99.94 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was available greater than or equal to 99.93 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but was available greater than or equal to 99.92 % of the calendar year.	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.92% of the calendar year Or The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE failed to have a minimum accuracy of 0.001 Hz.
R4.	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to make available information indicating missing or invalid data associated with

						Reporting ACE to its operators.
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.2% of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Process to identify and mitigate errors affecting the scan rate~~scan-rate~~ accuracy of data used in the calculation of Reporting ACE.
R7.	Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a common source for Tie Lines~~Tie-Lines~~, Pseudo-ties and

						Dynamic Schedules with its Adjacent Balancing Authorities **Or** **The Balancing Authority failed to use a time synchronized common source for hourly megawatt hour values that are agreed-upon to aid in the identification and mitigation of errors.**

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition

0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	

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.

A. Introduction

1. **Title:** ~~Automatic Generation~~ Balancing Authority Control

2. **Number:** BAL-005-~~0.2b~~1

3. **Purpose:** This standard establishes requirements for ~~Balancing Authority Automatic Generation Control (AGC)~~acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE~~) and to routinely deploy the Regulating Reserve.~~). The standard also ~~ensures that all facilities~~specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and ~~load electrically synchronized to~~for providing the ~~Interconnection are included within~~ information to the ~~metered boundary of a Balancing Area so that balancing of resources and demand can be achieved~~System Operator.

4. **Applicability:**

~~1.1. Balancing Authorities~~

~~1.2. Generator Operators~~

~~1.3. Transmission Operators~~

4.1. ~~Load Serving~~Functional Entities:

4.1.1. Balancing Authority

Effective Date: ~~May 13, 2009~~ See Implementation Plan for BAL-005-1

~~B.~~ Requirements

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

Rationale for Requirement R1: Real-time operation of a Balancing Authority requires real-time information. A sufficient scan rate is key to an Operator's trust in real-time information. Without a sufficient scan rate, an operator may question the accuracy of data during events, which would degrade the operator's ability to maintain reliability.

R1. The Balancing Authority shall ~~Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.~~use a design scan rate of no more than six seconds in acquiring data necessary to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M1. Each Balancing Authority will have dated documentation demonstrating that the data necessary to calculate Reporting ACE was designed to be scanned at a rate of no more than six seconds. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R2: The RC is responsible for coordinating the reliability of bulk electric systems for member BA's. When a BA is unable to calculate its ACE for an extended period of time, this information must be communicated to the RC within 15 minutes thereafter so that the RC has sufficient knowledge of system conditions to assess any unintended reliability consequences that may occur on the wide area.

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

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

~~**R1.** Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retirement approved by NERC BOT pending applicable regulatory approval.)~~

~~**R2.** A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.~~

R2. ~~.~~ A Balancing Authority ~~providing Regulation Service~~that is unable to calculate Reporting ACE for more than 30-consecutive minutes shall notify its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M2. Each Balancing Authority will have dated records to show when it was unable to calculate Reporting ACE for more than 30 consecutive minutes and that it notified its Reliability Coordinator within 45 minutes of the beginning of the inability to calculate Reporting ACE. Such evidence may include, but is not limited to, dated voice recordings, operating logs, or other communication documentation.

Rationale for Requirement R3: Frequency is the basic measurement for interconnection health, and a critical component for calculating Reporting ACE. Without sufficient

available frequency data the BA operator will lack situational awareness and will be unable to make correct decisions when maintaining reliability.

R3. Each Balancing Authority shall use frequency metering equipment for the calculation of Reporting ACE: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

3.1. that is available a minimum of 99.95% for each calendar year; and,

3.2. with a minimum accuracy of 0.001 Hz.

M3. The Balancing Authority shall ~~the Host~~have evidence such as dated documents or other evidence in hard copy or electronic format showing the frequency metering equipment used for the calculation of Reporting ACE had a minimum availability of 99.95% for each calendar year and had a minimum accuracy of 0.001 Hz to demonstrate compliance with Requirement R3.

Rationale for Requirement R4: System operators utilize Reporting ACE as a primary metric to determine operating actions or instructions. When data inputs into the ACE calculation are incorrect, the operator should be made aware through visual display. When an operator questions the validity of data, actions are delayed and the probability of adverse events occurring can increase.

~~R1.~~R4. The Balancing Authority ~~for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.~~shall make available to the operator information associated with Reporting ACE including, but not limited to, quality flags indicating missing or invalid data. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. Each~~A~~ Balancing Authority Area shall have evidence such as a graphical display or dated alarm log that provides indication of data validity for the real-time Reporting ACE based on both the calculated result and all of the associated inputs therein.

Rationale for Requirement R5: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

R1.1.

R5. Each Balancing Authority's system used to calculate Reporting ACE shall be available a minimum of 99.5% of each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M5. Each Balancing Authority will have dated documentation demonstrating that the system necessary to calculate Reporting ACE has a minimum availability of 99.5% for each calendar year. Acceptable evidence may include historical data, dated archive files; or data from other databases, spreadsheets, or displays that demonstrate compliance.

Rationale for Requirement R6: Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002. Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system.

A successful Operating Process must include the ability for hourly accumulated Tie Line MWH values to be agreed-upon between Balancing Authority Areas to aid in the identification errors and assign such errors to the appropriate Balancing Authority Areas for mitigation if necessary.

Instantaneous tie line flows between BAs cannot be effectively compared in real time. Methods to confirm accuracy of instantaneous metering is achieved through other means. The integration of instantaneous metered values is compared with accumulated MWh values to determine the accuracy of (error included in) the instantaneous metering for each BA. This comparison indicates the accuracy (amount of error) for each BA's own instantaneous metering as compared to its own accumulated MWh metering. However, it does not confirm that the accumulated MWh metering for one BA is equivalent to the accumulated MWh metering for the adjacent BA on the same tie line. This can only be confirmed by comparing the accumulated MWh value for one BA to the accumulated MWh value for the adjacent BA. If these two values are the same, any problem with the metering is identified by the difference between the integrated instantaneous MWhs and the accumulated MWh for that BA. However, if there is a difference between the accumulated MWhs between the two adjacent BAs, those BAs must agree upon a common value to use for that hour for that tie line in order to assign responsibility for managing the error represented by the difference between their accumulated values. If the BAs do not agree upon a value, the difference between the accumulated values will not be included in their error mitigation process and that error will therefore be passed to the interconnection as a frequency control burden.

R6. Each Balancing Authority ~~receiving Regulation Service~~that is within a multiple Balancing Authority Interconnection shall implement an Operating Process to identify and mitigate errors affecting the accuracy of scan rate data used in the calculation of

Reporting ACE for each Balancing Authority Area. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M6. Each Balancing Authority shall have a current Operating Process meeting the provisions of Requirement R6 and evidence to show that the process was implemented, such as dated communications or incorporation in System Operator task verification.

Rationale for Requirement R7: Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Common source data is critical to calculating Reporting ACE that is consistent between Balancing Authorities. When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action.

The intent of Requirement R7 Part 7.1 is to provide accuracy in the measurement and calculations used in Reporting ACE. It specifies the need for common metering points for instantaneous values for the Tie Line megawatt flow values between Balancing Authority Areas. Common data source requirements also apply to instantaneous values for pseudo-ties and dynamic schedules, and can extend to more than two Balancing Authorities that participate in allocating shares of a generation resource in supplementary regulation, for example.

The intent of Requirement R7 Part 7.2 is to enable accuracy in the measurements and calculations used in Reporting ACE. It specifies the need for common metering points for hourly accumulated values for the time synchronized tie line MWh values agreed-upon between Balancing Authority Areas. These time synchronized agreed-upon values are necessary for use in the Operating Process required in R6 to identify and mitigate errors in the scan rate values used in Reporting ACE.

R7. Each Balancing Authority shall ensure that ~~backup plans are in place~~each Tie Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**R3.**~~ a common source to provide ~~replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.~~

~~1.1.~~7.1. ~~The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single~~information to both Balancing Authorities ~~operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability~~

~~Coordinator.~~for the scan rate values used in the calculation of Reporting ACE; and,

7.2. a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors under the Operating Process as developed in Requirement R6.

~~**R4.**~~ The Balancing Authority shall ~~operate AGC continuously unless~~have dated evidence such ~~operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.~~

~~The Balancing Authority shall ensure~~as voice recordings or transcripts, operator logs, electronic communications, or other equivalent evidence that ~~data acquisition~~ will be used to demonstrate a common source for ~~and~~ the components used in the calculation of Reporting ACE ~~occur at least every six seconds.~~

~~**R5.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.~~

~~**R6.** The Balancing Authority shall include all Interchange Schedules~~ with its Adjacent Balancing ~~Authorities in the calculation of Net Scheduled Interchange for the ACE equation.~~

~~**R6.5.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.~~

~~**R7.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.~~

~~Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.~~Authority

~~**R8.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.~~

~~**R8.5.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.~~

~~**R8.6.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.~~

~~Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.~~

~~Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.~~

~~The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.~~

~~**R9.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.~~

~~**R10.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.~~

~~**R11.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:~~

~~Device~~	~~Accuracy~~
~~Digital frequency transducer~~	~~≤ 0.001 Hz~~
~~MW, MVAR, and voltage transducer~~	~~≤ 0.25 % of full scale~~
~~Remote terminal unit~~	~~≤ 0.25 % of full scale~~
~~Potential transformer~~	~~≤ 0.30 % of full scale~~
~~Current transformer~~	~~≤ 0.50 % of full scale~~

~~C. Measures~~

~~**M1.**~~**M7.** ~~Not specified~~.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

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

~~1.1.1. Within one week upon request, Balancing Authorities shall provide~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional ~~Reliability Organization CPS source data~~ Entity in ~~daily CSV files~~their respective roles of monitoring and enforcing compliance with ~~time stamped one minute averages of: 1) ACE and 2) Frequency Error.~~

~~Within one week upon request, Balancing Authorities shall provide~~ the NERC ~~or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance~~Reliability Standards.

~~**1.2. Compliance Monitoring Period and Reset Timeframe**~~

~~Not specified.~~

1.2. ~~Data~~Evidence Retention

~~1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.~~

~~1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.~~

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 applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable entity shall keep data or evidence to show compliance for the current year, plus three previous calendar years.

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.

~~1.3.~~1.4. Additional Compliance Information

~~Not specified.~~

~~**Levels**~~None

Table of ~~Non-~~Compliance Elements

~~Not specified.~~

R #	Time Horizon	VRF	Violation Severity Levels		
			Lower VSL	Moderate VSL	High VSL
R1.	Real-time Operations	Medium	N/A	N/A	N/A
R2.	Real-time Operations	Medium	The Balancing Authority failed to notify its Reliability Coordinator within 45 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator within no more than 50 minutes from the beginning of the inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 50 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator with mo more than 55 minutes from the beginning of an inability to calculate Reporting ACE.	The Balancing Authority failed to notify its Reliability Coordinator within 55 minutes of the beginning of a 30-minute inability to calculate Reporting ACE but notified its Reliability Coordinator with no more than 60 minutes from the beginning of an inability to calculate Reporting ACE.
R3.	Real-time Operations	Medium	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.95% of the calendar year but	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.94% of the calendar year but was	The Balancing Authority's frequency metering equipment used for the calculation of Reporting ACE was available less than 99.93% of the calendar year but

			was available greater than or equal to 99.94 % of the calendar year.	available greater than or equal to 99.93 % of the calendar year.	was available greater than or equal to 99.92 % of the calendar year.
R4.	Real-time Operations	Medium	N/A	N/A	N/A
R5.	Operations Assessment	Medium	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.5% of the calendar year but was available greater than or equal to 99.4 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.4% of the calendar year but was available greater than or equal to 99.3 % of the calendar year.	The Balancing Authority's system used for the calculation of Reporting ACE was available less than 99.3% of the calendar year but was available greater than or equal to 99.2 % of the calendar year.
R6.	Same-day Operations	Medium	N/A	N/A	N/A

R7.	Operations Planning	Medium	N/A	N/A	N/A	

D. Regional ~~Differences~~Variances

None.

E. Interpretations

None~~None identified~~.

~~E.~~F. Associated Documents

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

None.

Version History

Version	Date	Action	Change
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to "0.1b"	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from "BAL-005-1" to "BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	

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.

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

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
SAR posted for comment	July 16, 2014
Standard posted for 45-day comment period and initial ballot	July 30, 2015
Standard posted for a 45-day comment period and successive ballot	November 10, 2016

Anticipated Actions	Date
Final ballot	January – February 2016
NERC Board adoption	February 2016

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: None

A. Introduction

1. Title: **Facility Interconnection Requirements**

2. Number: FAC-001-3

3. Purpose: To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner

4.1.2 Applicable Generator Owner

4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. Effective Date: See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems that new or materially modified Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems that new or materially modified Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3.
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

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

This is the second posting of the draft standard for a 45-day formal comment period with an additional ballot.

Completed Actions	Date
Standards Committee approved SAR for posting	June 10, 2014
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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: None

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. Procedures for confirming with those responsible for the reliability of affected systems ~~of~~ that new or materially modified ~~transmission~~ Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. Procedures for confirming with those responsible for the reliability of affected systems ~~of~~that new or materially modified ~~generation~~ Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address two parts of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner failed to address Requirement R3 Part 3.1 through Part 3.3.
R4	Long-term Planning	Lower	N/A	The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address two parts of Requirement R4 Part 4.1 through Part 4.3.	The Generator Owner failed to address Requirement R4 Part 4.1 through Part 4.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

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- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

A. Introduction

1. **Title:** **Facility Interconnection Requirements**

2. **Number:** FAC-001-~~2~~3

3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Applicable Generator Owner

   4.1.2.1 ~~**4.1.2.1**~~ Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

~~1. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is one year after the date that this 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 one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

5. **Effective Date:** See Implementation Plan for FAC-001-3.

B. Requirements and Measures

R1. ~~**R1.**~~ Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. generation Facilities;

1.2. transmission Facilities; and

1.3. end-user Facilities.

M1. ~~**M1.**~~ Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.

R2. Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.

Rationale for Requirement R3.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the transmission will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 3.3, the Transmission Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R3. Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-~~-~~Term Planning]*

3.1. Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).

3.2. Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.

3.3. ~~**M3.**~~ Procedures for confirming with those responsible for the reliability of affected systems that new or materially modified Facilities are within a Balancing Authority Area's metered boundaries.

M3. Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.

~~**R4.**~~

Rationale for Requirement R4.3: Consistent with the Functional Model, there cannot be an assumption that the entity owning the generation will be the same entity providing the BA function. It is the responsibility of the party interconnecting to make appropriate arrangements with a Balancing Authority to ensure its Facilities are within the BA's metered boundaries, which also serves to facilitate the process of the coordination between the two entities that will be required under numerous other standards upon the start of operation. Under 4.3, the Generator Owner is responsible for confirming that the party interconnecting has made appropriate provisions with a Balancing Authority to operate within its metered boundaries.

R4. Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

4.1. Procedures for coordinated studies of new interconnections and their impacts on affected system(s).

4.2. Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.

4.3. ~~**M4.**~~ Procedures for confirming with those responsible for the reliability of affected systems that new or materially modified Facilities are within a Balancing Authority Area's metered boundaries.

M4. Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable Functional Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

The responsible entities shall retain documentation as evidence for three years.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	N/A	The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available	The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request. OR The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.	The Transmission Owner did not document Facility interconnection requirements.

				upon request, but failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.

R3	Long-term Planning	Lower	N/A	~~N/A~~The Transmission Owner failed to address one part of Requirement R3 Part 3.1 through Part 3.3.	The Transmission Owner ~~addressed either~~failed to address two parts of Requirement R3~~,~~ Part 3.1 ~~or~~through Part 3.~~2 in its Facility interconnection requirements, but did not address both.~~3.	The Transmission Owner ~~addressed neither~~failed to address Requirement R3~~,~~ Part 3.1 ~~nor~~through Part 3.~~2 in its Facility interconnection requirements.~~3.
R4	Long-term Planning	Lower	N/A	~~N/A~~The Generator Owner failed to address one part of Requirement R4 Part 4.1 through Part 4.3.	The ~~applicable~~ Generator Owner ~~addressed either~~failed to address two parts of Requirement R4~~,~~ Part 4.1 ~~or~~through Part 4.~~2 in its Facility interconnection requirements, but did not address both.~~3.	The ~~applicable~~ Generator Owner ~~addressed neither~~failed to address Requirement R4~~,~~ Part 4.1 ~~nor~~through Part 4.~~2 in its Facility interconnection requirements.~~3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was "materially modified." Recognizing that what constitutes a "material modification" will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control
- BAL-006-2 – Inadvertent Interchange - Requirement R3

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

Actual Net Interchange (NI_A): The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.

Scheduled Net Interchange (NI_S): The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Interchange Meter Error (I_{ME}): A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Automatic Time Error Correction (I_{ATEC}): 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 Mode.

The absolute value of I_{ATEC} shall not exceed L_{max} .

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

- L_{max} is the maximum value allowed for I_{ATEC} set by each BA between 0.2*|B_i| and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange (PII_{hourly}) is $(1-Y) * (II_{actual} - B_i * \Delta TE/6)$
- 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\textbf{PII}_{accum}^{on/offpeak} = last\ period's\ \textbf{PII}_{accum}^{on/offpeak} + \textbf{PII}_{hourly}$$

Reporting ACE: The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Automatic Generation Control (AGC): A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 Requirement R3 will be retired concurrently with the effective date for BAL-005-1 . Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

after the effective date of the applicable governmental authorities order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of Automatic Generation Control, Pseudo Tie and Balancing Authority shall be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

Implementation Plan

Project 2010-14.2.1 Balancing Authority Reliability-based Controls Reliability Standard BAL-005-1

Requested Approval

- BAL-005-1 – Balancing Authority Controls

Requested Retirement

- BAL-005-0.2b – Automatic Generation Control
- BAL-006-2 – Inadvertent Interchange - Requirement R3

Prerequisite Approval

- FAC-001-3 – Facility Interconnection Requirements

Revisions to Glossary Terms

The following definitions shall become effective when BAL-005-1 becomes effective:

Actual Frequency (F_A): The Interconnection frequency measured in Hertz (Hz).

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$$\mathbf{I}_{ATEC} = \frac{\mathbf{PII}_{accum}^{on/off\ peak}}{(1-Y)*H}$$ when operating in Automatic Time Error Correction Mode.

The absolute value of $\mathbf{I}_{ATEC}$ shall not exceed L_{max} .

$\mathbf{I}_{ATEC}$ shall be zero when operating in any other AGC mode.

- L_{max} is the maximum value allowed for $\mathbf{I}_{ATEC}$ set by each BA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $L_{10} = 1.65 * \varepsilon_{10} \sqrt{(-10B_i)(-10B_S)}$.
- 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.
- $Y = B_i / B_S$.
- H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3.
- B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
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- Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B_i * 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 Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\mathbf{PII}_{accum}^{on/offpeak} = last\ period's\ \mathbf{PII}_{accum}^{on/offpeak} + \mathbf{PII}_{hourly}$$

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

Reporting ACE is calculated as follows:

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

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

Where:

- NI_A = Actual Net Interchange.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,

4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

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Pseudo-Tie: A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Applicable Entities

- Balancing Authority

Applicable Facilities

- N/A

Background

Reliability Standard BAL-005-1 addresses Balancing Authority Reliability-based Controls and establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). Reliability Standard BAL-005-1 (Balancing Authority Controls) and associated Implementation Plan was developed in conjunction with FAC-001-3 to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented immediately after BAL-005-1 becomes effective as reflected in the Implementation Plan for FAC-001-3, and BAL-006-2 Requirement R3 will be retired concurrently with the effective date for BAL-005-1 . Finally, to ensure proper coordination with BAL-001-2, approved by the Commission in Order No. 810 issued on April 16, 2015, the following definitions associated with BAL-005-1 will be implemented concurrently with the effective date for BAL-001-2:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

Effective Dates

Definitions

The definitions of the following terms shall become effective immediately after the effective date of BAL-001-2[1]:

- Reporting ACE
- Actual Frequency
- Actual Net Interchange
- Scheduled Net Interchange
- Interchange Meter Error
- Automatic Time Error Correction

BAL-005-1

Where approval by an applicable governmental authority is required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months

[1] Because the definition of "Reporting ACE" associated with BAL-005-1 will become effective immediately after the effective date of BAL-001-2, the definition of "Reporting ACE" that was approved by the Commission on April 16, 2015 in Order No. 810 (151 FERC ¶ 61,048) will never go into effect.

after the effective date of the applicable governmental authorities order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, BAL-005-1 and associated definitions, except the definitions enumerated in the section directly above, shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees', or as otherwise provided for in that jurisdiction.

Retirements

BAL-005-0.2b (Automatic Generation Control) shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

BAL-006-2 (Inadvertent Interchange) Requirement R3 shall be retired immediately prior to the Effective Date of BAL-005-1 (Balancing Authority Controls) in the particular jurisdiction in which the revised standard is becoming effective.

The existing definitions of -Automatic Generation Control, Pseudo Tie and Balancing Authority shall be retired at midnight of the day immediately prior to the effective date of BAL-005-1, in the jurisdiction in which the new standard is becoming effective.

The existing definitions of Reporting ACE, Actual Frequency, Actual Net Interchange, Scheduled Net Interchange, Interchange Meter Error, and Automatic Time Error Correction shall be retired immediately after the effective date of BAL-001-2.[2]

[2] Note that the definition of Reporting ACE that was approved by the Commission in Order No. 810, which will replace the existing definition of Reporting ACE, will be retired immediately prior to the effective date for the revised definition of Reporting ACE, as described above. As such, the definition of Reporting ACE approved by the Commission in Order No. 810 will never go into effect.

Implementation Plan

Reliability Standard BAL-006-2

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2 will be retired concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2 shall be retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

Implementation Plan

Reliability Standard BAL-006-2~~3~~

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- N/A~~BAL-006-3 – Inadvertent Interchange~~

Requested Retirement

- BAL-006-2 – Inadvertent Interchange

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Prerequisite Events

- NERC Operating Committee approval of Inadvertent Interchange Guideline[1]

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, BAL-006-2~~3~~ will be retired~~implemented~~ concurrently with the effective date of BAL-005-1 and requisite approval of Inadvertent Interchange Guideline, as reflected in the "Prerequisite Approvals" and "Prerequisite Events" sections above.

Effective Dates

[1] Reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not binding norms or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

BAL-006-2~~3~~ shall be~~come effective~~ retired on the effective date of BAL-005-1 and the approval of Inadvertent Interchange Guideline.

~~Retirements~~

~~BAL-006-2 (Inadvertent Interchange) shall be retired immediately prior to the Effective Date of BAL-006-3 (Inadvertent Interchange) in the particular jurisdiction in which the revised standard is becoming effective.~~

Implementation Plan

Reliability Standard FAC-001-3

Project 2010-14.2.1 Balancing Authority Reliability-based Controls

Requested Approval

- FAC-001-3 – Facility Interconnection Requirements

Requested Retirement

- FAC-001-2 – Facility Interconnection Requirements

Prerequisite Approval

- BAL-005-1 – Balancing Authority Controls

Revisions to Glossary Terms

- None

Applicable Entities

- Balancing Authority

Background

Reliability Standard FAC-001-3 addresses Facility Interconnection Requirements, which ensure the avoidance of adverse impacts on the reliability of the Bulk Electric System by requiring Transmission Owners and applicable Generator Owners to document and make Facility interconnection requirements available so that entities seeking to interconnect will have necessary information. Reliability Standard FAC-001-3 and associated Implementation Plan was developed in conjunction with BAL-005-1 (Balancing Authority Controls) to ensure that entities with facilities and Load operating in an Interconnection are within a Balancing Authority Area's metered boundaries. This coordination will allow for the collection of data necessary to calculate Reporting Area Control Error (Reporting ACE) to achieve the best results under BAL-005-1.

General Considerations

To guarantee proper coordination as intended by the standard drafting team for Project 2010-14.2.1, FAC-001-3 will be implemented concurrently with BAL-005-1, as reflected in the "Prerequisite Approvals" section above.

Effective Dates

FAC-001-3 shall become effective on the effective date of BAL-005-1.

Retirements

FAC-001-2 (Facility Interconnection Requirements) shall be retired immediately prior to the Effective Date of FAC-001-3 (Facility Interconnection Requirements) in the particular jurisdiction in which the revised standard is becoming effective.

Calculating and Using Reporting ACE in a Tie Line Bias Control Program

Introduction:

Tie Line Bias[1] (TLB) control has been used as the preferred control method in North America for 75 years. In the early 1950's the term Area Control Error (ACE) was developed for the specific implementation of coordinated Tie Line Bias control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE[2] in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary; reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the Bulk Electric System.

The following definitions are included in the NERC Glossary:

Definition:
Actual Frequency **F_A** **5/11/2015**
The Interconnection frequency measured in Hertz (Hz).

Definition:
Actual Net Interchange **NI_A** **5/11/2015**
The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, with all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange.

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[1] Capitalized terms hold the same definition as in the NERC glossary throughout this document.

[2] The CPS1 measure was among the first of the results based measures developed by NERC. It defined not how to perform control, but instead defined the target control results that were to be achieved, and a method to measure whether or not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, Area Control Error (ACE) has been used to describe many terms involved in TLB Control. Within a BAA's Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions in order to smooth the control signals; or, there may be additional "feed-forward" terms added to ACE in anticipation of future changes (e.g. anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting to improve the quality of control for the specific characteristics of that particular BAA.

Some auditors have raised compliance issue related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in BAL-001. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Definition:

Automatic Time Error Correction $\mathbf{I_{ATEC}}$ **5/11/2015**

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 (PII) to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection.

$$\boldsymbol{I}_{\mathbf{ATEC}} = \frac{\boldsymbol{PII}_{accum}^{on/off\ peak}}{(\mathbf{1-Y})*\mathbf{H}}$$ when operating in Automatic Time Error Correction mode.

The absolute value of $\mathbf{I_{ATEC}}$ shall not exceed $\mathbf{L_{max}}$ **.**

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

- $\mathbf{L_{max}}$ is the maximum value allowed for $\mathbf{I_{ATEC}}$ set by each BAA between $0.2*|B_i|$ and L_{10}, $0.2*|B_i| \leq L_{max} \leq L_{10}$.
- $\mathbf{L_{10}} = 1.65 * \varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$.
- $\boldsymbol{\varepsilon_{10}}$ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection.
- **Y** = B_i / B_S.
- **H** = Number of hours used to payback primary Inadvertent Interchange energy. The value of H is set to 3.
- $\mathbf{B_i}$ = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz).
- $\mathbf{B_S}$ = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz).
- Primary Inadvertent Interchange ($\mathbf{PII_{hourly}}$) is (1-Y) * (II_{actual} – B_i * ΔTE/6)
- $\mathbf{II_{actual}}$ 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: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE_{offset})$
- $\mathbf{TD_{adj}}$ 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.
- $\mathbf{TE_{offset}}$ is 0.000 or +0.020 or -0.020.
- $\mathbf{PII_{accum}}$ is the Balancing Authority Area's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required,

  where:

$$\boldsymbol{PII}_{accum}^{on/offpeak} = \boldsymbol{last\ period's}\ \boldsymbol{PII}_{accum}^{on/offpeak} + \boldsymbol{PII}_{hourly}$$

Definition:

Frequency Bias Setting **B** **4/1/2015**

A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority Area's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Definition:

Interchange Meter Error $\mathbf{I_{ME}}$ **5/11/2015**

A term, normally zero, used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.

Definition:

Reporting ACE **RACE** **5/11/2015**

The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for 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.
- NI_S = Scheduled Net Interchange.
- B = Frequency Bias Setting.
- F_A = Actual Frequency.
- F_S = Scheduled Frequency.
- I_{ME} = Interchange Meter Error.
- I_{ATEC} = Automatic Time Error Correction.

All NERC Interconnections with multiple Balancing Authority Areas 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 BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:

1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss;
2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;
3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and,
4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)

Definition:
Scheduled Frequency **F_S** **3/16/2007**
60.0 Hz, except during a manual Time Error Correction.

Definition:
Scheduled Net Interchange **NI_S** **5/11/2015**
The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.

Structure:

The effective use of Reporting ACE within a TLB control program should address the following components:

(I) Management Roles and Expectations
(II) Information Technology Roles
(III) System Operator Roles
(IV) Manual Source Data Entry
(V) Automatically Collected Source Data
(VI) Uses of Reporting ACE
(VII) Historic Data Management
(VIII) Special Conditions and Calculations

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the Tie Line Bias control program.

Each responsible entity should evaluate all of its uses for Reporting ACE in its operations and its reliability measurement. Reporting ACE is one of the most important single measurements available to indicate the current state of the Responsible Entity's contribution to interconnection reliability.[3] Reporting ACE is also used as an integral part of the measurements used in BAL-001 and BAL-002. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in BAL-003 and BAL-005.

I. Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Tie Line Bias control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

a. Set expectations for safety, reliability, and operational performance.

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[3] When configured with a Frequency Bias Setting equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match its actual interchange, less the impact from its current Frequency Response offset, to its scheduled interchange.

b. Assure that a TLB control program exists for each responsible entity and is current.
c. Provide annual training on the TLB control program and its purpose and requirements.
d. Ensure the proper expectation of TLB control program performance.
e. Share insights across industry associations.

II. Information Technology (IT) Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE and source information are always current and correct.
c. Implement the TLB control program in Real-time.
d. Ensure that the EMS supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.
e. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.
f. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the following calculations and equations:

1) Actual Net Interchange[4] (NI_A):

All BAAs involved account for the power exchange and associated transmission losses as actual interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout all of their energy accounting processes.

i. Calculate for each scan.[5]
ii. Integrated hourly average calculated for each hour as an integration of the scan rate values.

[4] By definition "Actual megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.

[5] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

2) Scheduled Net Interchange[6] (NI_S):
   i. Calculate for each scan.
   ii. Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

   Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout all of their energy accounting processes.

3) Frequency Error ($\Delta F = (F_A - F_S)$):
   i. Calculate for each scan.
   ii. Calculate clock-minute average from valid samples available within each clock-minute[7] where at least half of the scan-rate samples are valid.

4) Frequency Trigger Limit – Low (FTL_{Low})[8]:

   Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

5) Frequency Trigger Limit – High (FTL_{High})[9]:

   Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

6) Accumulated primary Inadvertent Interchange (PII): Calculated each hour for WECC BAAs only.

$$\boldsymbol{PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}}$$

7) Automatic Time Error Correction (IATEC): Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

$$\boldsymbol{I_{ATEC}} = \frac{\boldsymbol{PII_{accum}^{on/off\ peak}}}{\boldsymbol{(1-Y)*H}} \text{ when operating in ATEC mode.}$$

The absolute value of **I_{ATEC}** shall not exceed **L_{max}** **.**

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

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[6] By definition "Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC tie lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

[7] Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

[8] This variable could be entered manually as long as it is changed every time a manual time error correction is started or stopped. If manual time error correction is eliminated, it could become a constant and entered manually.

8) Reporting ACE:
   i. Calculate for each scan.
   ii. Calculated average for each clock-minute for BAAs using a fixed Frequency Bias Setting when at least half of the values are valid.[9]

9) Compliance Factor[10]:
   i. Calculate for each scan where both Reporting ACE and Frequency Error are valid.
   ii. Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[11]

10) Clock-hour compliance factor[8]:

    Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

11) Month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid clock-minute compliance factors in the month.

12) 12-month compliance factor[8]:

    Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

13) CPS1 compliance factor:

    Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the Epsilon_1 value for the Interconnection.

14) CPS1:
   i. Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.
   ii. Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.
   iii. Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2

[9] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid.

[10] Used for CPS1.

[11] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the Frequency Bias Setting for those BAs using a variable Frequency Bias Setting, where at least half of the ratio values are valid and the average clock-minute Frequency Error is valid.

and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

iv. Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

v. Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

15) Balancing Authority ACE Limit - Low ($BAAL_{Low}$):

i. Calculate the scan rate Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – Low by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

16) Balancing Authority ACE Limit - High ($BAAL_{High}$):

i. Calculate the scan rate Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the Frequency Error.

ii. Calculate the clock-minute Balancing Authority ACE Limit – High by multiplying three times Epsilon1 squared for the interconnection by -10 times the Frequency Bias Setting and dividing the result by the clock-minute Frequency Error when at least half of the values are valid.

17) Balancing Authority ACE Limit - Low Compliance:

i. Alarm $BAAL_{Low}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$.

ii. Indicate $BAAL_{Low}$ non-compliance for each period where the clock-minute Reporting ACE is below the clock-minute $BAAL_{Low}$ for more than 30-consecutive clock-minutes.

18) Balancing Authority ACE Limit - High Compliance:

i. Alarm $BAAL_{High}$ potential non-compliance for each period as determined for operations where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$.

ii. Indicate $BAAL_{High}$ non-compliance for each period where the clock-minute Reporting ACE is above the clock-minute $BAAL_{High}$ for more than 30 consecutive clock minutes.

g. Ensure that the EMS supports the retention of all historic data including data quality information required to be retained to support continuing operations and audit requirements.

h. Ensure that the EMS supports and manages the presentation of all information required to be available to the System Operator for real-time operations, operations staff for evaluation of operations, and auditors for compliance confirmation.

i. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.

III. System Operator and Operations Staff Roles

a. Participate in appropriate TLB control related training.
b. Ensure the Reporting ACE information is always current and correct.
c. Conduct an evaluation of the effectiveness of the TLB control program and incorporate lessons learned.
d. Implement the TLB control program in Real-time.

IV. Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[12], by the Responsible Entity's Energy Management System (EMS), and may be partially based on source data manually entered into that system. The following source data may be entered:

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent Balancing Authority Areas may not be available from an automatic collection source, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent Balancing Authority Areas entering the manual data. If the actual flow estimates are the same for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

NI_S (Scheduled Net Interchange): The power transfer schedules, including the schedule ramps where applicable, are processed by the EMS. If scheduled flow estimates are equal and have opposite signs for the Adjacent Balancing Authority Areas, the effect of any errors will be confined to the two Adjacent Balancing Authority Areas responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The Frequency Bias Setting, or minimum required value, for the Balancing Authority Area is specified by calculations performed as part of compliance with BAL-003-1 - Frequency Response and Frequency Bias Setting;

R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area 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

[12] BAL-005-1 Balancing Authority Control - R2. The Balancing Authority shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE.

(ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.[13]

10 is the factor (10 0.1Hz/Hz) that converts the Frequency Bias Setting units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor as specified in BAL-004-0.[14] It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all times.

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the System Operator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for **I_{ATEC}** set by each BA between $0.2*|B|$ and L_{10}, $0.2*|B| \leq L_{max} \leq L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is normally set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum Frequency Bias Settings for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the interconnection.

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[13] As a note of interest, the new procedures put forth with BAL-003-1 will result in the reduction of minimum Frequency Bias Setting values on the multiple BA interconnections to bring them closer to the natural measured Frequency Response of the interconnection. The rule requiring a minimum Frequency Bias Setting of 1% of peak load in the NERC Standards dates back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response which was 2% of peak load at that time. The 1% figure is now more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid.

[14] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

V. Automatically Collected Source Data

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds[15], by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the System Operators. This data quality information is presented to the System Operator to have situational awareness with respect to the quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as CPS1, BAAL, DCS, and frequency response obligation (FRM).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[16,17,18,19] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the System Operator to support situational awareness.[20] The EMS sums the individual flow values on all tie lines and pseudo ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry element is passed to the result of all calculations using that element.

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent Balancing Authority Area, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent Balancing Authority Area for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005[21] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

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[15] BAL-005-1 Balancing Authority Control – "R2. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[16] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS. See the attached document titled "Anti-aliasing Filtering."

[17] It is acceptable to collect tie-line flow data from RTUs that use report by exception as long as those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[18] The six-second scan rate not only assures that data collected is close to Real-time, it also limits the latency (time skew) associated with the data collection.

[19] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[20] Indications of suspect data are usually indicated with color changes and/or alarms.

[21] BAL-005 – Automatic Generation Control specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the Digital Frequency Transducer.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange. (Block schedules are not used for this calculation.)

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

VI. **Uses of Reporting ACE**

a. Reporting ACE is currently used to measure secondary frequency control within TLB control on all of the Interconnections.[22] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing Standards. The following standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

   i. BAL-001-1 – Real Power Balancing Control Performance and BAL-001-2 – Real Power Balancing Control Performance.

   ii. BAL-002-1 – Disturbance Control Performance and BAL-002-2 – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved).

   iii. BAL-005-0.2b – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved).

   iv. BAL-006-2 Inadvertent Interchange.

b. The industry may also consider the use of Reporting ACE in the future to evaluate the rules associated with transmission loading.

VII. **Historic Data Management**

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and "TLB control program".

VIII. **Special Conditions and Calculations**

IX. **I_{ME} (Interchange Meter Error):** BAL-005-1 R6 requires, "Each Balancing Authority Area that is within a multiple Balancing Authority Area interconnection shall implement an Operating Process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE." Ideally, errors identified should be corrected immediately, but this is not always possible. The $\mathbf{I_{ME}}$ term, normally zero, can be used by the System Operator or operations staff to add a correction term in the Reporting ACE calculation correcting errors affecting the scan-rate accuracy of data, thus mitigating the error in the calculation of Reporting ACE until telemetry errors can be corrected.

[22] On single BAA Interconnections, the ACE Equation reduces to a single term, $\mathbf{-10B\ (F_A - F_S)}$, because there are no tie lines or schedules to include in the first term, $\mathbf{(NI_A - NI_S)}$, and there is no $\mathbf{I_{ME}}$ term to correct for tie line or dynamic schedule measurement errors in the first term.

The calculation of the $\mathbf{I_{ME}}$ is the one of the results of this required Operating Process. It compensates for data or equipment errors affecting components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs. The process used for including adjustments in the $\mathbf{I_{ME}}$ term should be based on good quality control methods.[23]

The goal associated with the use of the $\mathbf{I_{ME}}$ is to encourage the scan-rate values of actual and scheduled interchange between Adjacent Balancing Authorities to be equal in magnitude and have opposite signs.[24] Unfortunately, these values cannot be directly compared with each other because of differences between scan time and differences between scan-rates between BAAs. When initially configured, all BAs used "Digital to Analog" converters and "Analog to Digital" converters to transmit tie-line flows and accumulated MWh values from the common metering point required in the standards to the BA's EMS. These "D to A" and "A to D" converters are subject to error and require frequent calibration, and although, many have been replaced by digital telemetry, they still exist and require oversight. Any difference between the scan-rate values agreed to by Adjacent BAAs that is not included in the error mitigation process will be passed to the interconnection for management and will not be included in the performance measures such as CPS1, BAAL and FRM.

Energy Management Systems are capable of integrating the scan-rate values used for the calculation of Reporting ACE and providing those integrated values for comparison to the accumulated megawatt-hour values for the same meters. If the integrated scan rate values are close to the accumulated megawatt-hour values, then one can conclude that the scan-rate values accurately represent the accumulated values. The final step in this process includes a comparison and agreement on the accumulated megawatt-hour values between the Adjacent BAAs sharing the measurement. If the differences between accumulated values between Adjacent BAAs is not included in this process, any adjustments to the accumulated values made by a BAA to achieve agreement with an adjacent BAA will be excluded from the analysis and will not be mitigated. This information used in conjunction with a similar analysis of the scan rate values for the same measurement by the Adjacent Balancing Authority Area including analysis of any differences between the accumulated values and the agreed to accumulated values. This total process provides reasonable assurance that the scan-rate tie line flows or the dynamic schedules used by Adjacent BAAs are consistent with one another confining control problems within the boundaries of the Adjacent BAAs.

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[23] Adjustments to the $\mathbf{I_{ME}}$ term should follow good quality control methods and exclude tampering as demonstrated by the Deming's Funnel Experiment, http://blog.newsystemsthinking.com/w-edwards-deming-and-the-funnel-experiment/ .

[24] As long as the scan-rate tie line flows and scheduled flows match for Adjacent Balancing Authority Areas, any problems with the measurement of balancing on the interconnection will be confined to within the boundaries of those Adjacent Balancing Authority Areas. Any mismatch will pass the difference to the interconnection and will result in frequency control error that will to be excluded from performance measurement and managed by all BAAs through the frequency bias terms of their Reporting ACE.

These error correction adjustments can be used to correct errors in the **NI_A** or **NI_S**[25] terms for Reporting ACE and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the **I_{ME}** term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-1.

a. **Use of Source-Sink Pairs for Asynchronous DC Tie Lines to Another Interconnection:** One of the primary rules for insuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie lines, pseudo ties, interchange schedules and Dynamic Schedules to Adjacent Balancing Authority Areas and only Adjacent Balancing Authority Areas on the same Interconnection, and requiring the exclusion of all asynchronous DC tie lines and associated scheduled interchange with Balancing Authority Areas on a different Interconnection from Reporting ACE. Following this simple rule insures that all loads, losses and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie line bias control program. One terminal of an asynchronous DC tie line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie line will exclude the asynchronous tie line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

[25] Errors in the **NI_S** would only occur and only support correction in cases where there is a measurement error associated with a Dynamic Schedule.

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Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Final Ballots Open through February 8, 2016

Now Available

Final ballots for **BAL-005-1 – Balancing Authority Control** and **FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange** are open through **8 p.m. Eastern, Monday, February 8, 2016.**

Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pools may cast a vote. All ballot pool members may change their previously cast votes. 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 pools associated with this project may log in and submit their votes for the standards here. If you experience any difficulties using the Standards Balloting & Commenting System (SBS), 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 https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The voting results for the standards will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process
For more information on the Standards Development Process, please 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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3353 Peachtree Rd, NE
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Standards Announcement

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls
BAL-005-1, BAL-006-2, and FAC-001-3

Final Ballot Results

Now Available

Final ballots for **BAL-005-1 –Balancing Authority Control, FAC-001-3 – Facility Interconnection Requirements,** and the recommended retirement of **BAL-006-2 – Inadvertent Interchange,** concluded **8 p.m. Eastern, Monday, February 8, 2016.**

The standards received sufficient affirmative votes for approval. Voting statistics are listed below, and the following links provide detailed results:

- BAL-005-1
- BAL-006-2
- FAC-001-3

.	Quorum / Approval
BAL-005-1	86.35% / 72.06%
BAL-006-2	86.98% / 94.61%
FAC-001-3	86.67% / 80.15%

Next Steps
The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process
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: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1 FN 2 ST
Voting Start Date: 1/29/2016 12:01:00 AM
Voting End Date: 2/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 272
Total Ballot Pool: 315
Quorum: 86.35
Weighted Segment Value: 72.06

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	78	1	47	0.77	14	0.23	0	8	9
Segment: 2	10	0.9	4	0.4	5	0.5	0	0	1
Segment: 3	72	1	43	0.796	11	0.204	0	8	10
Segment: 4	25	1	18	0.947	1	0.053	0	2	4
Segment: 5	72	1	33	0.717	13	0.283	0	13	13
Segment: 6	44	1	25	0.714	10	0.286	0	5	4
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment: 10	8	0.8	5	0.5	3	0.3	0	0	0
Totals:	315	7	177	5.044	58	1.956	0	37	43

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	N/A
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Negative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	N/A

1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Affirmative	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		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	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	Tom Hanzlik		Affirmative	N/A

	Gas Co.				
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	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		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	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		Affirmative	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		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Negative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Negative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove	Mark Schultz		Affirmative	N/A

	Springs				
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A

3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	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		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Negative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	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	PNM Resources	Michael Mertz		None	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	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		Negative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A

3	Turlock Irrigation District	James Ramos		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	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		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	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		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation	Spencer Tacke		None	N/A

	District				
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Stephanie Little		Negative	N/A
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A

5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Negative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	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	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Negative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Negative	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		Negative	N/A

5	NextEra Energy	Allen Schriver		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Negative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		Abstain	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	M Lee Thomas		Negative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		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		Negative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New	Robert Winston		Negative	N/A

	York				
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lower Colorado River Authority	Michael Shaw		None	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		Negative	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		Negative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
6	Platte River Power	Carol Ballantine		Affirmative	N/A

	Authority				
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Negative	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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts	Frederick Plett		Affirmative	N/A

	Attorney General				
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Negative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-006-2 FN 2 ST
Voting Start Date: 1/29/2016 12:01:00 AM
Voting End Date: 2/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 274
Total Ballot Pool: 315
Quorum: 86.98
Weighted Segment Value: 94.61

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	78	1	58	0.967	2	0.033	0	9	9
Segment: 2	10	1	8	0.8	2	0.2	0	0	0
Segment: 3	72	1	55	1	0	0	0	7	10
Segment: 4	25	1	17	1	0	0	0	4	4
Segment: 5	72	1	47	0.979	1	0.021	0	12	12
Segment: 6	44	1	34	0.971	1	0.029	0	5	4
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	2	0.2	1	0.1	1	0.1	0	0	0

Segment: 10	8	0.8	8	0.8	0	0	0	0	0
Totals:	315	7.1	229	6.717	7	0.383	0	38	41

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Wes Wingen		Abstain	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	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	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
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	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	William Smith		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	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.	Charles Raney		Affirmative	N/A

1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	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		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	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	Tom Hanzlik		Affirmative	N/A

	Gas Co.				
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	Steve Johnson		None	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		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	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		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Abstain	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	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		Affirmative	N/A
3	City of Green Cove	Mark Schultz		Affirmative	N/A

	Springs				
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A

3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	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		Affirmative	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		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A

3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	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		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Abstain	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		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	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		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Abstain	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Modesto Irrigation	Spencer Tacke		None	N/A

	District				
4	Oklahoma Municipal Power Authority	Ashley Stringer		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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	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		None	N/A
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Abstain	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A

5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	N/A
5	Exelon	Vince Catania		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Abstain	N/A
5	Florida Municipal Power Agency	David Schumann		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	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	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Affirmative	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Mike Avesing		Affirmative	N/A
5	NB Power Corporation	Rob Vance		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	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		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Teresa Czyz		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Pacific Gas and Electric Company	Alex Chua		Abstain	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		Abstain	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	M Lee Thomas		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		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 Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New	Robert Winston		Affirmative	N/A

	York				
6	Dominion - Dominion Resources, Inc.	Louis Slade		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Dave Carlson		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lower Colorado River Authority	Michael Shaw		None	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		Affirmative	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		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
6	Platte River Power	Carol Ballantine		Affirmative	N/A

	Authority				
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Affirmative	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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts	Frederick Plett		Affirmative	N/A

	Attorney General				
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Negative	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	Southwest Power Pool Regional Entity	Bob Reynolds		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: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls FAC-001-3 FN 2 ST
Voting Start Date: 1/29/2016 12:01:00 AM
Voting End Date: 2/8/2016 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 273
Total Ballot Pool: 315
Quorum: 86.67
Weighted Segment Value: 80.15

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	78	1	50	0.781	14	0.219	0	4	10
Segment: 2	10	0.9	5	0.5	4	0.4	0	0	1
Segment: 3	72	1	49	0.817	11	0.183	0	2	10
Segment: 4	25	1	19	0.95	1	0.05	0	2	3
Segment: 5	72	1	44	0.786	12	0.214	0	4	12
Segment: 6	44	1	31	0.816	7	0.184	0	2	4
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	2	0.1	1	0.1	0	0	0	1	0
Segment: 9	2	0.1	1	0.1	0	0	0	1	0

Segment: 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals:	315	6.8	206	5.45	50	1.35	0	17	42

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	American Transmission Company, LLC	Andrew Pusztai		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Phil Hart		Affirmative	N/A
1	Avista - Avista Corporation	Bryan Cox	Rich Hydzik	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		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A

1	Bonneville Power Administration	Donald Watkins		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	Bryan Texas Utilities	John Fontenot		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	Affirmative	N/A
1	Colorado Springs Utilities	Shawna Speer		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Chris de Graffenried		Negative	N/A
1	Dairyland Power Cooperative	Robert Roddy		Negative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	N/A
1	Duke Energy	Doug Hils		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	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	Georgia Transmission Corporation	Jason Snodgrass		Negative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		None	N/A

1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Abstain	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane		Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Teresa Cantwell		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	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		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Alan MacNaughton		None	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Negative	N/A
1	NiSource - Northern Indiana Public Service Co.	Charles Raney		Negative	N/A

1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Rod Kinard	Tammy Porter	Negative	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		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	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	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	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	Tom Hanzlik		Affirmative	N/A

	Gas Co.				
1	Seattle City Light	Pawel Krupa	Michael Watkins	Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Denise Stevens		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Robert A. Schaffeld		Affirmative	N/A
1	Southwest Transmission Cooperative, Inc.	John Shaver		Negative	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		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	United Illuminating Co.	Jonathan Appelbaum		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	Steve Johnson		None	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		Affirmative	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	New York Independent System Operator	Gregory Campoli		Negative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman	William Temple	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		None	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	Anaheim Public Utilities Dept.	Dennis Schmidt		None	N/A
3	APS - Arizona Public Service Co.	Jeri Freimuth		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Shuye Teng		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Negative	N/A
3	BC Hydro and Power Authority	Faramarz Amjadi		Affirmative	N/A
3	Beaches Energy Services	Steven Lancaster		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Thomas Mielnik	Darnez Gresham	Negative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Green Cove	Mark Schultz		Affirmative	N/A

	Springs				
3	City of Leesburg	Chris Adkins		Affirmative	N/A
3	City of Redding	Elizabeth Hadley	Bill Hughes	Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		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		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Negative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski	Oshani Pathirane	Abstain	N/A

3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lakeland Electric	David Hadzima		None	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	Los Angeles Department of Water and Power	Mike Anctil		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	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		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Negative	N/A
3	NiSource - Northern Indiana Public Service Co.	Ramon Barany		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	PHI - Potomac Electric Power Co.	Mark Yerger		Affirmative	N/A
3	PNM Resources	Michael Mertz		None	N/A

3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	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		None	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		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		Affirmative	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		None	N/A
3	WEC Energy Group, Inc.	James Keller		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	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		Affirmative	N/A
4	Blue Ridge Power Agency	Duane Dahlquist		Affirmative	N/A
4	City of Clewiston	Lynne Mila		Affirmative	N/A
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		Affirmative	N/A
4	City of Redding	Nick Zettel	Bill Hughes	Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Julie Hegedus		Affirmative	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		Affirmative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	Illinois Municipal Electric Agency	Bob Thomas		Affirmative	N/A
4	Keys Energy Services	Stanley Rzad		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation	Spencer Tacke		None	N/A

	District				
4	Oklahoma Municipal Power Authority	Ashley Stringer		Affirmative	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		None	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	South Mississippi Electric Power Association	Steve McElhaney		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		Abstain	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	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		None	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Steve Wenke		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Negative	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	Calpine Corporation	Hamid Zakery		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City and County of San Francisco	Daniel Mason		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City of Redding	Paul Cummings	Bill Hughes	Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Cogentrix Energy Power Management, LLC	Mike Hirst		None	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Brian O'Boyle	Kelly Dash	Negative	N/A
5	Dominion - Dominion Resources, Inc.	Randi Heise		Abstain	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Michael McSpadden		Affirmative	N/A

5	Entergy - Entergy Services, Inc.	Tracey Stubbs		None	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		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	N/A
5	Great River Energy	Preston Walsh		Negative	N/A
5	Hydro-Qu?bec Production	Roger Dufresne		Abstain	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Kenneth Silver		Affirmative	N/A
5	Lower Colorado River Authority	Dixie Wells		Negative	N/A
5	Luminant - Luminant Generation Company LLC	Rick Terrill		Affirmative	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	NB Power Corporation	Rob Vance		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Wayne Sipperly		Negative	N/A

5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Michael Melvin		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Leo Staples		Affirmative	N/A
5	Oglethorpe Power Corporation	Bernard Johnson		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	N/A
5	Pacific Gas and Electric Company	Alex Chua		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	Portland General Electric Co.	Matt Jastram		None	N/A
5	PPL Electric Utilities Corporation	Dan Wilson		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	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	SCANA - South Carolina Electric and Gas Co.	Henry Delk		None	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		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	M Lee Thomas		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	stephanie johnson		Affirmative	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 Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	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	Bill Hughes	Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New	Robert Winston		Negative	N/A

	York				
6	Dominion - Dominion Resources, Inc.	Louis Slade		Negative	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		Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Chris Gowder	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Chris Bridges	Douglas Webb	Negative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lower Colorado River Authority	Michael Shaw		None	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		Negative	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		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
6	Platte River Power	Carol Ballantine		Affirmative	N/A

	Authority				
6	Portland General Electric Co.	Shawn Davis		None	N/A
6	PPL - Louisville Gas and Electric Co.	OELKER LINN		Affirmative	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 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		Abstain	N/A
6	TECO - Tampa Electric Co.	Benjamin Smith		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Peter Colussy	Amy Casuscelli	Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
8	Massachusetts	Frederick Plett		Affirmative	N/A

	Attorney General				
9	City of Vero Beach	Ginny Beigel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Southwest Power Pool Regional Entity	Bob Reynolds		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 O

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005, BAL-006, FAC-001

	Participant	Entity
Chair	Jerry Rust	Northwest Power Pool
Vice Chair	Thomas W. Siegrist	Brickfield Burchette Ritts and Stone, PC
Member	Brad Gordon	PJM Interconnection LLC
	Phillip Hart	AECI
	Doug Hils	Duke Energy
	Howard Illian	Energy Mark, Inc.
	Gary Nolan	Arizona Public Service
	Michael Potishnak	Spriteland Energy representing NPCC
	Sandip Sharma	Electric Reliability Council of Texas, Inc.
	Steve Swan	Midwest ISO, Inc.
NERC Staff	Darrel Richardson – Senior Standards Developer	North American Electric Reliability Corporation
	Candice Castaneda – Counsel	North American Electric Reliability Corporation
	Andrew Wills – Associate Counsel	North American Electric Reliability Corporation