Exhibit B

Proposed Reliability Standard Submitted for Approval

A. Introduction

Title: Frequency Response and Frequency Bias Setting

Number: BAL-003-1

Purpose: To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Applicability:

1.1. Balancing Authority

1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

1.2. Frequency Response Sharing Group

Effective Date:

1.3. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.

1.4. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Risk Factor: Medium][Time Horizon: Real-time Operations]*

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

1.1 Less than zero at all times, and

1.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

C. Measures

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.3. Data Retention

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

The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

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

1.4. Additional Compliance Information

For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation

	Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing

	Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

E. Regional Variance

None

F. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition

0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Starting Frequency (F_{Start})	**59.974**	**59.976**	**59.963**	**59.972**	Hz
Prevailing UFLS First Step	**59.5***	**59.5**	**59.3**	**58.5**	Hz
Base Delta Frequency (DF_{Base})	**0.474**	**0.476**	**0.663**	**1.472**	Hz
CC_{ADJ}	**0.007**	**0.004**	**0.012**	**N/A**	Hz
Delta Frequency (DF_{CC})	**0.467**	**0.472**	**0.651**	**1.472**	Hz
CB_R	**1.000**	**1.625**	**1.377**	**1.550**	
Delta Frequency (DF_{CBR})	**0.467**	**0.291**	**0.473**	**0.949**	Hz
BC'_{ADJ}	**0.018**	**N/A**	**N/A**	**N/A**	Hz
Max. Delta Frequency (MDF)	**0.449**	**0.291**	**0.473**	**0.949**	
Resource Contingency Criteria (RCC)	**4,500**	**2,740**	**2,750**	**1,700**	MW
Credit for Load Resources (CLR)		**300**	**1,400****		MW
IFRO	**-1,002**	**-840**	**-286**	**-179**	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that contains the sum of each participant’s individual event performance.

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

Frequency Response Measure (FRM)

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its

Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

Target Date	Activity
April 30	The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).
May 10	Form1 is posted with selected events from the first quarter for BA usage by the ERO.
May 15	The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.
July 15	The BAs provide load and generation data as described in Attachment A to the ERO.
July 30	The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).
August 10	Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.
October 30	The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)
November 10	Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.
November 20	If necessary, the ERO provides any updates to the necessary Frequency Response.
November 20	The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.
January 30	The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).
2nd business day in February	Form1 is posted with all selected events for the year for BA usage by the ERO.
February 10	The ERO assigns FRO values to the BAs for the upcoming year.
March 7	BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.
March 24	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.
Any time during first 3 business days of April (unless specified otherwise by the ERO)	The BA implements any changes to their FBS and L10 value.

Exhibit B

Proposed Reliability Standard Submitted for Approval

A. Introduction

Title: Frequency Response and Frequency Bias Setting

Number: BAL-003-1

Purpose: To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Applicability:

1.1. Balancing Authority

1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

1.2. Frequency Response Sharing Group

Effective Date:

1.3. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.

1.4. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Risk Factor: Medium][Time Horizon: Real-time Operations]*

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

1.1 Less than zero at all times, and

1.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

C. Measures

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.3. Data Retention

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

The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

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

1.4. Additional Compliance Information

For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation

	Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing

	Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

E. Regional Variance

None

F. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition

0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Starting Frequency (F_{Start})	**59.974**	**59.976**	**59.963**	**59.972**	Hz
Prevailing UFLS First Step	**59.5***	**59.5**	**59.3**	**58.5**	Hz
Base Delta Frequency (DF_{Base})	**0.474**	**0.476**	**0.663**	**1.472**	Hz
CC_{ADJ}	**0.007**	**0.004**	**0.012**	**N/A**	Hz
Delta Frequency (DF_{CC})	**0.467**	**0.472**	**0.651**	**1.472**	Hz
CB_R	**1.000**	**1.625**	**1.377**	**1.550**	
Delta Frequency (DF_{CBR})	**0.467**	**0.291**	**0.473**	**0.949**	Hz
BC'_{ADJ}	**0.018**	**N/A**	**N/A**	**N/A**	Hz
Max. Delta Frequency (MDF)	**0.449**	**0.291**	**0.473**	**0.949**	
Resource Contingency Criteria (RCC)	**4,500**	**2,740**	**2,750**	**1,700**	MW
Credit for Load Resources (CLR)		**300**	**1,400****		MW
IFRO	**-1,002**	**-840**	**-286**	**-179**	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that contains the sum of each participant’s individual event performance.

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

Frequency Response Measure (FRM)

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its

Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

Target Date	Activity
April 30	The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).
May 10	Form1 is posted with selected events from the first quarter for BA usage by the ERO.
May 15	The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.
July 15	The BAs provide load and generation data as described in Attachment A to the ERO.
July 30	The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).
August 10	Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.
October 30	The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)
November 10	Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.
November 20	If necessary, the ERO provides any updates to the necessary Frequency Response.
November 20	The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.
January 30	The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).
2^{nd} business day in February	Form1 is posted with all selected events for the year for BA usage by the ERO.
February 10	The ERO assigns FRO values to the BAs for the upcoming year.
March 7	BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.
March 24	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.
Any time during first 3 business days of April (unless specified otherwise by the ERO)	The BA implements any changes to their FBS and L10 value.

Exhibit C

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A Procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO shall post the suggested modification for a 45-day formal comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with FERC for informational purposes.

Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used by Balancing Authorities (BA) to calculate their Frequency Response to determine:

- Whether the BA met its Frequency Response Obligation, and
- An appropriate fixed Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS frequency excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the Frequency Response Measure (FRM) calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining FRS compliance. This is described later.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    - *a.* The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        - i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        - *ii.* Point C is the arrested value of frequency observed within 12 seconds following the start of the excursion.

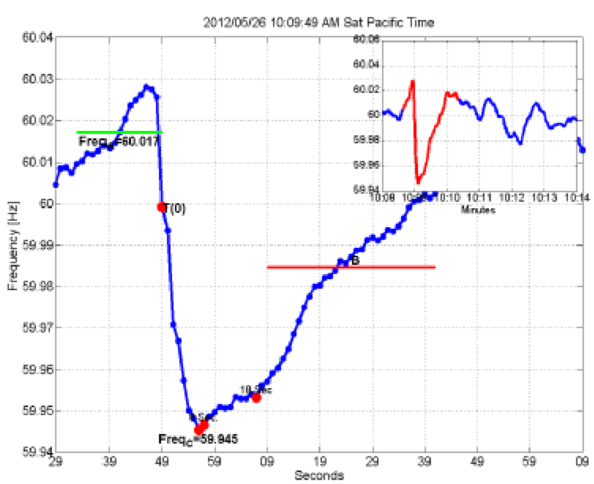
Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

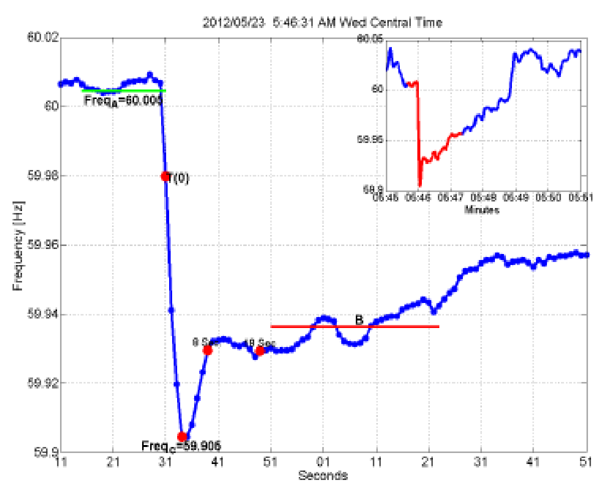
Table 1: Interconnection Frequency Excursion Threshold Values

b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.

c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.





5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.

6. Frequency excursion events occurring during periods:

    (i) when large interchange schedule ramping or load change is happening, or

    (ii) *w*ithin 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion *e*vents occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24 month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of BAL-003-1. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Monthly

Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".

Quarterly

The monthly event lists will be reviewed quarterly with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard",* events will be selected to populate the FRS Form 1 for each Interconnection. The Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS' Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.

The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-1, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each interconnection. In the first year, the minimum Frequency Bias Setting for each interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT*	N/A
HQ*	N/A

Table 2. Frequency Bias Setting Minimums

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. If an Interconnection’s total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection’s total natural Frequency Response by more (in absolute value) than 0.2 percentage points of peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Interconnection Frequency Response Obligation Methodology

This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).

The following are the formulae that comprise the calculation of the IFROs.

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARCC = RCC - CLR$$

$$IFRO = \frac{ARCC}{10 * MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- CC_{Adj} is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of the Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RCC is the resource contingency criteria.
- CLR is the credit for load resources.
- ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Exhibit D

Frequency Response Standard Background Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Frequency Response Standard Background Document

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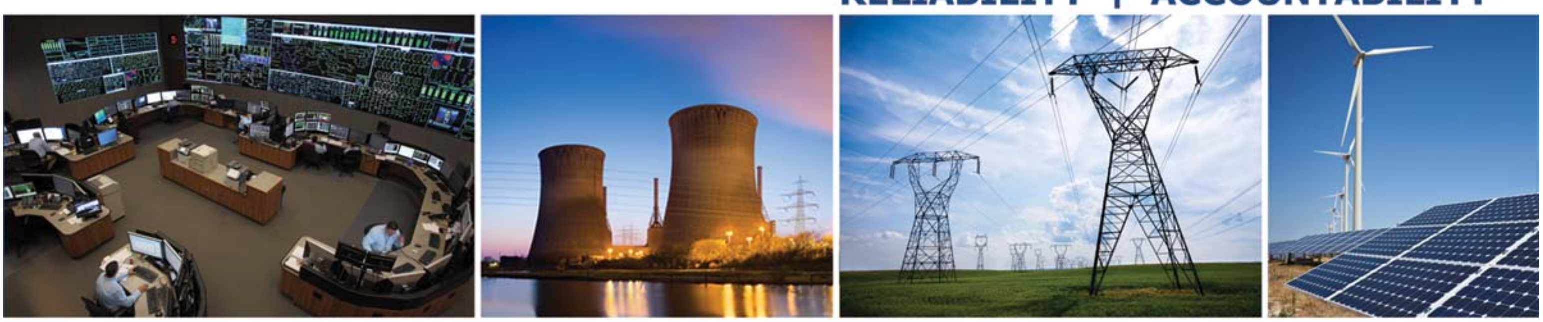
RELIABILITY | ACCOUNTABILITY



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Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

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

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

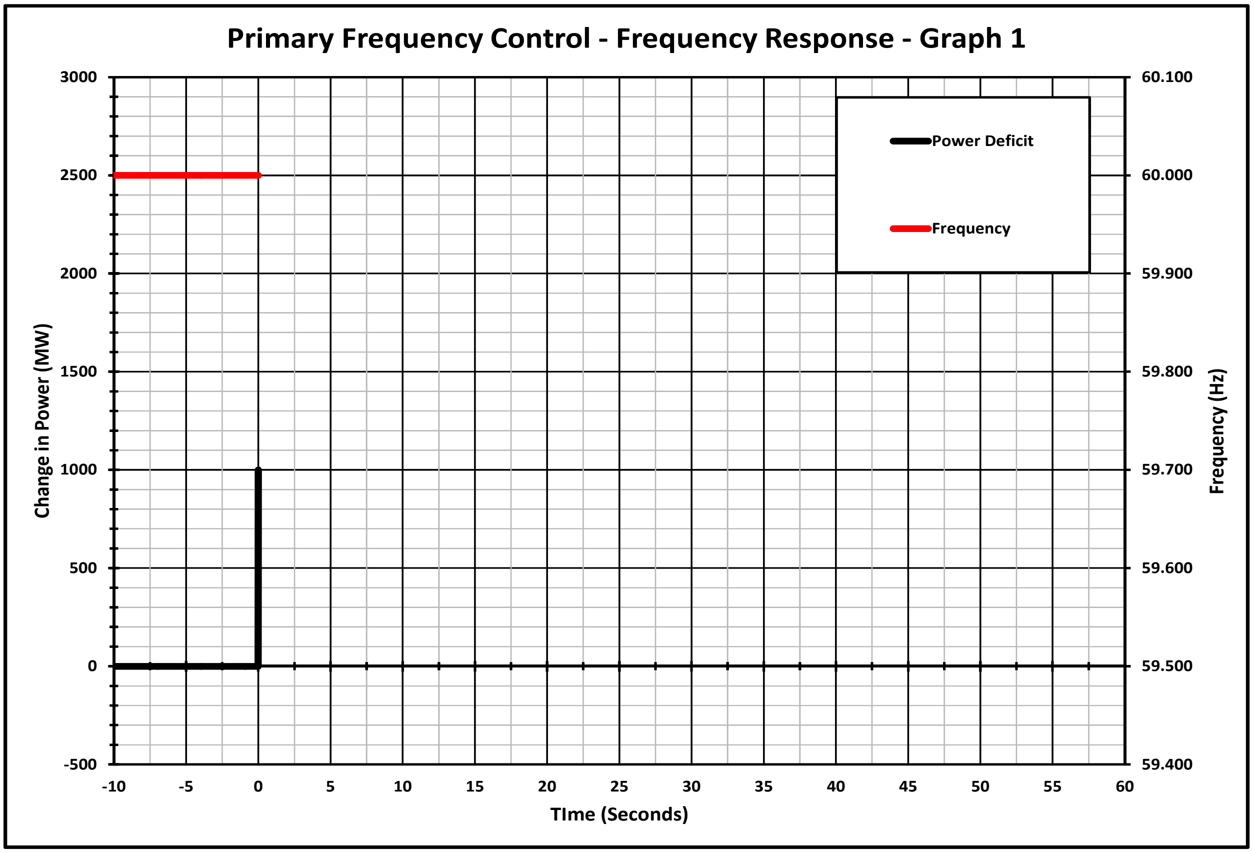
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

Frequency Response Illustration

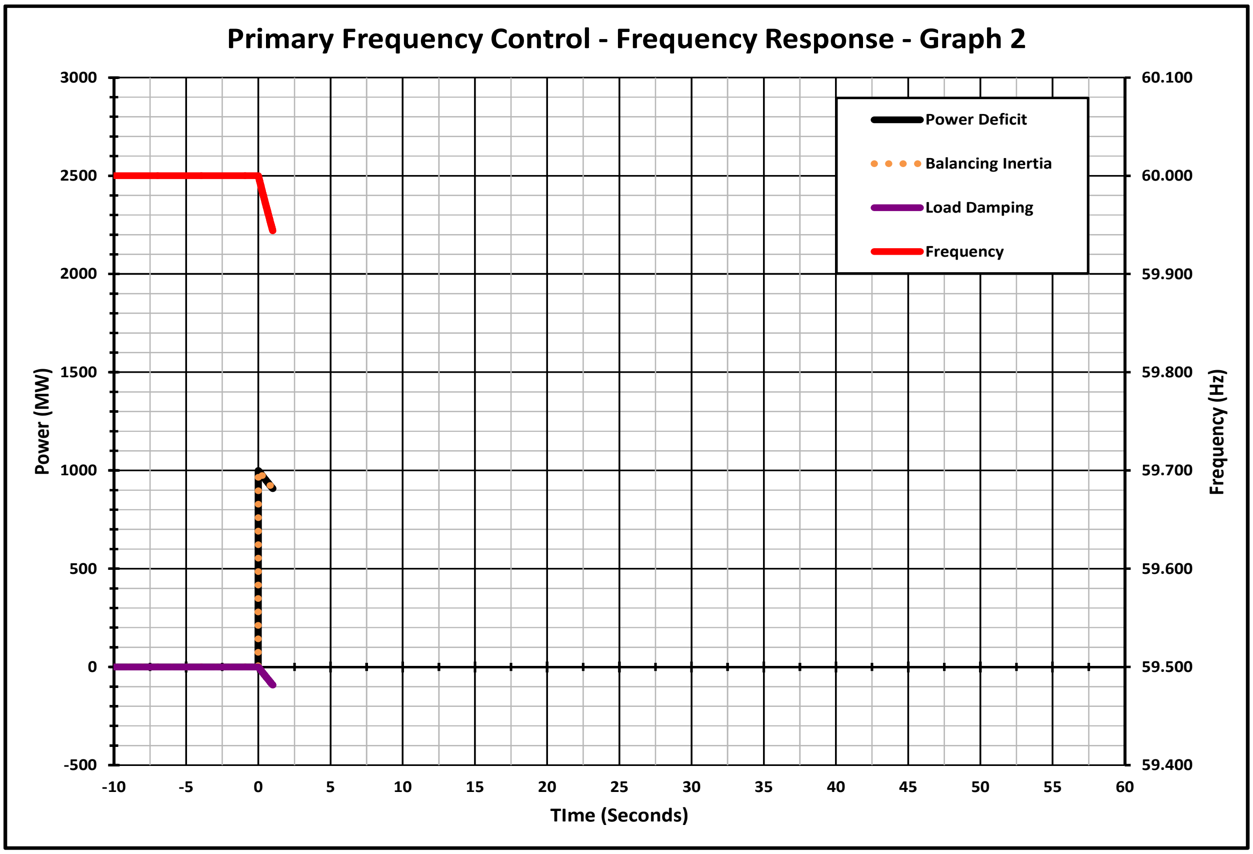
The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for



Frequency Response.

The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

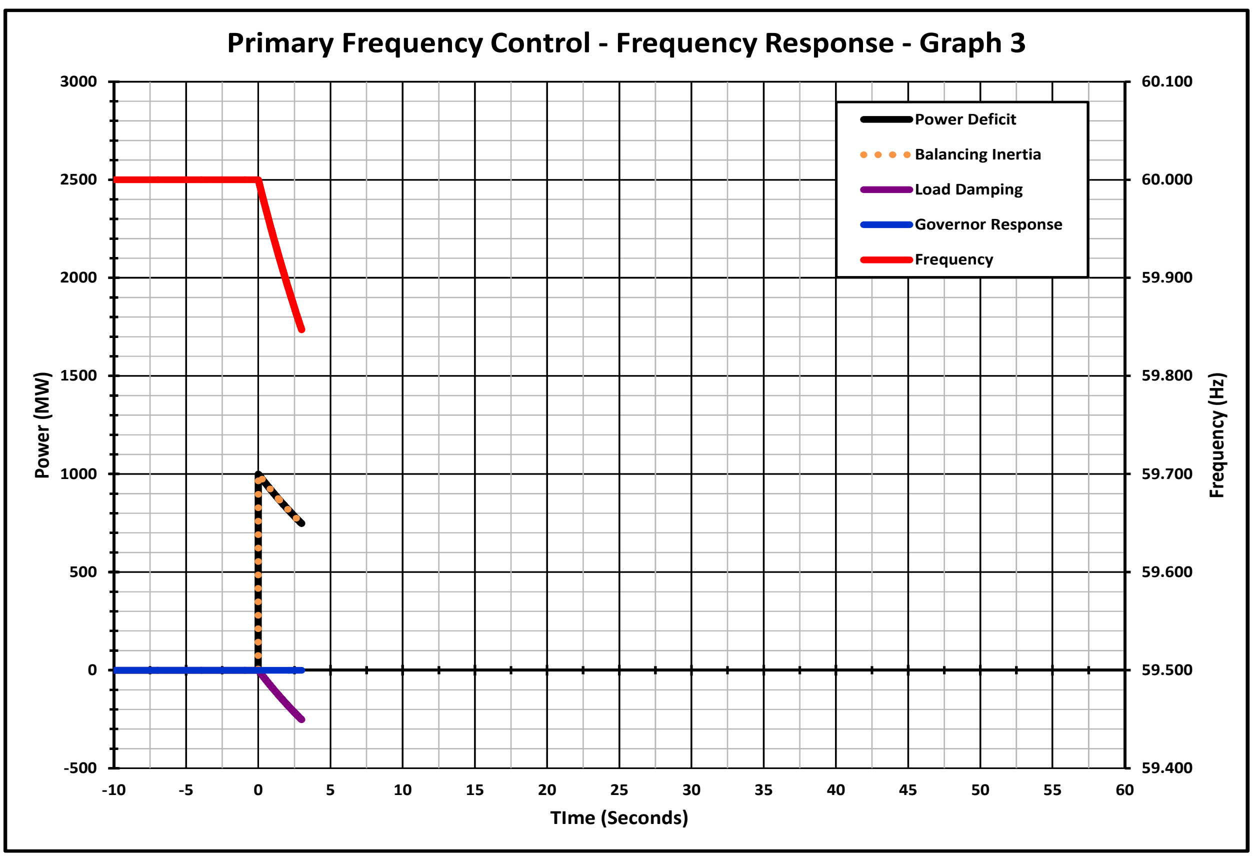
3 The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

4 The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

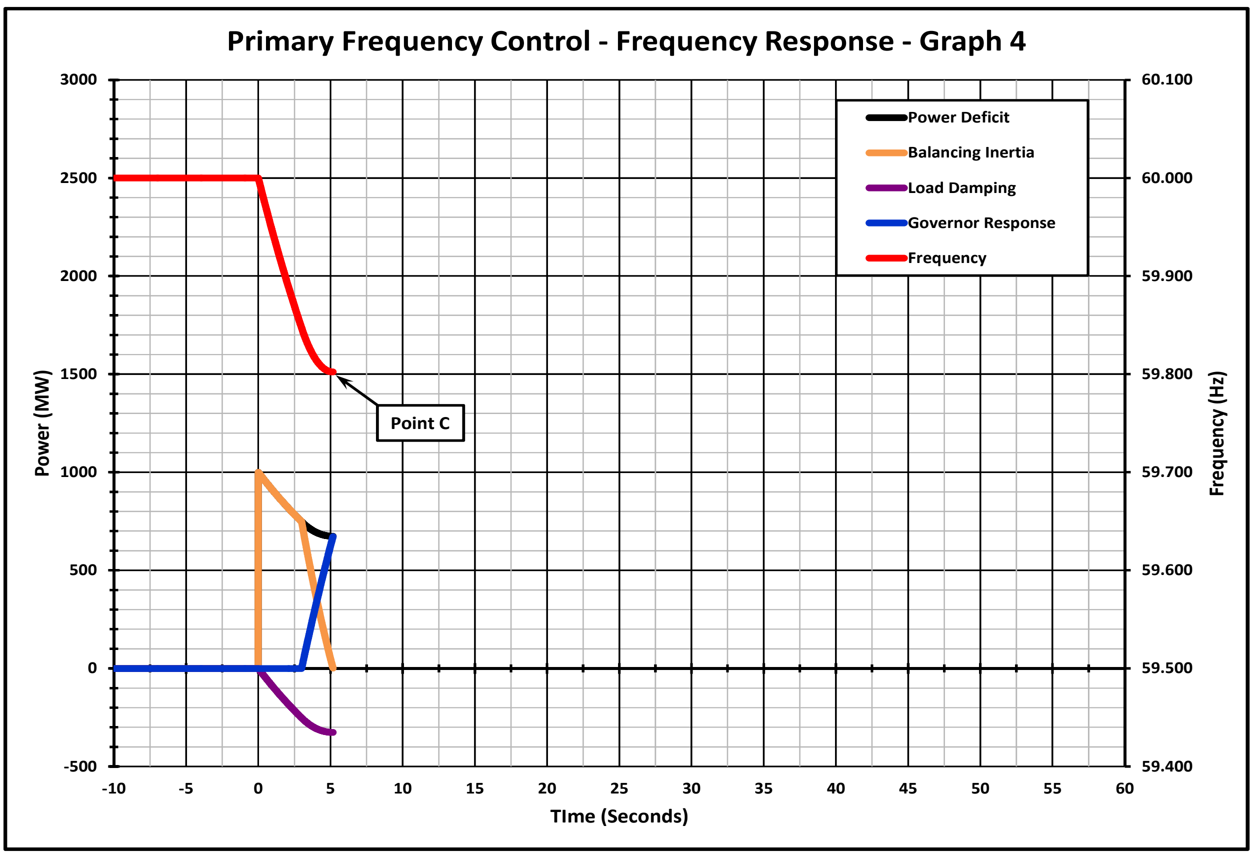
It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



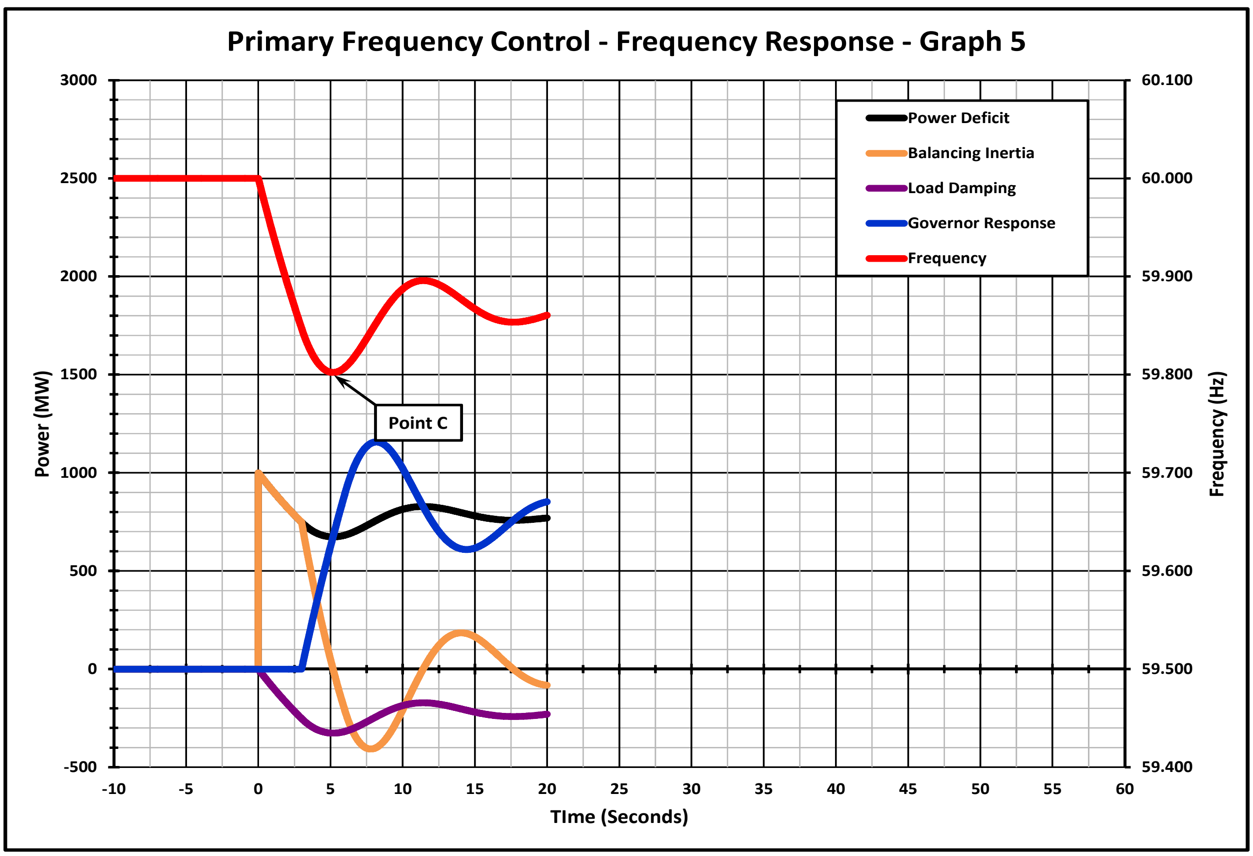
Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.

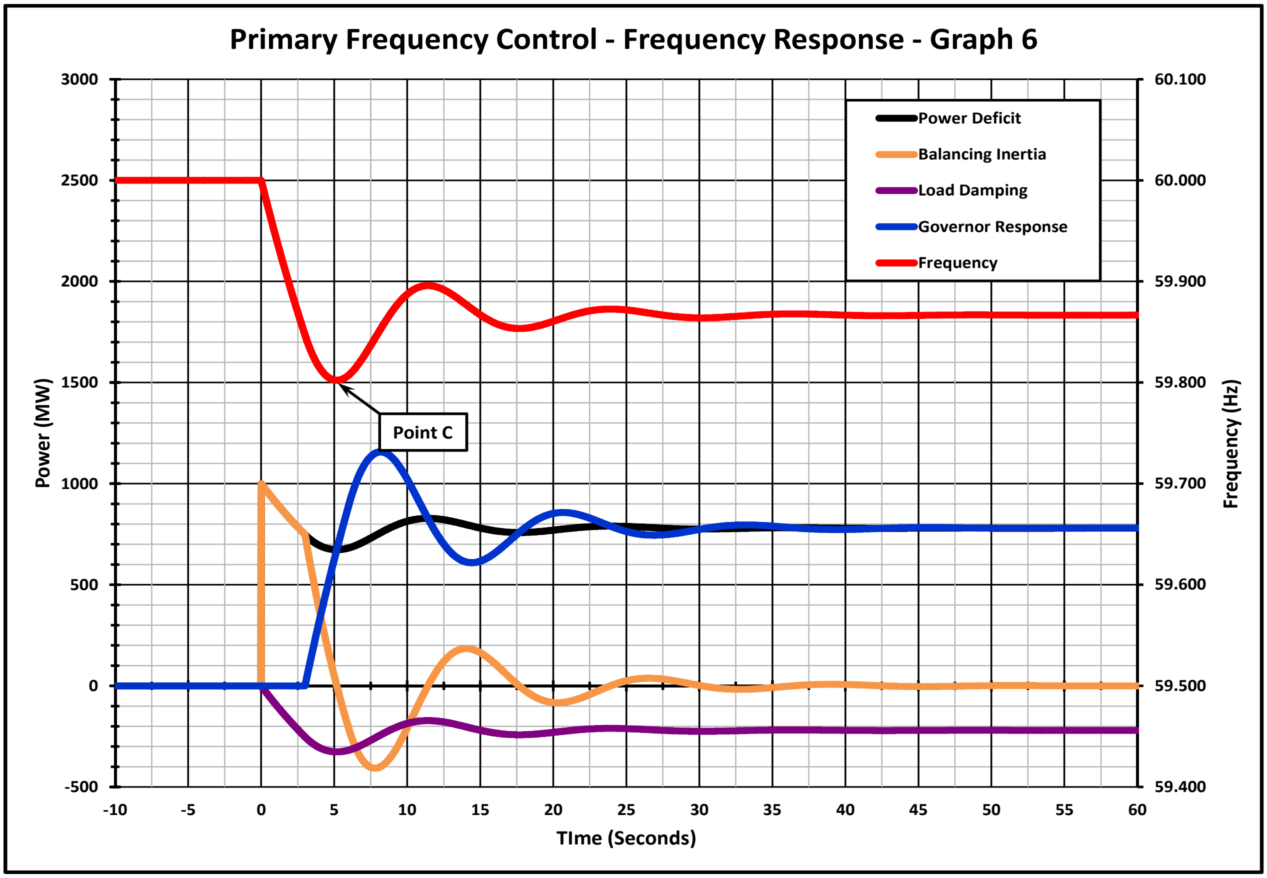


This point, at which the frequency is first arrested, is defined as "Point C" and Frequency Response calculated at this point is called the "**arrested frequency response**." The arrested frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

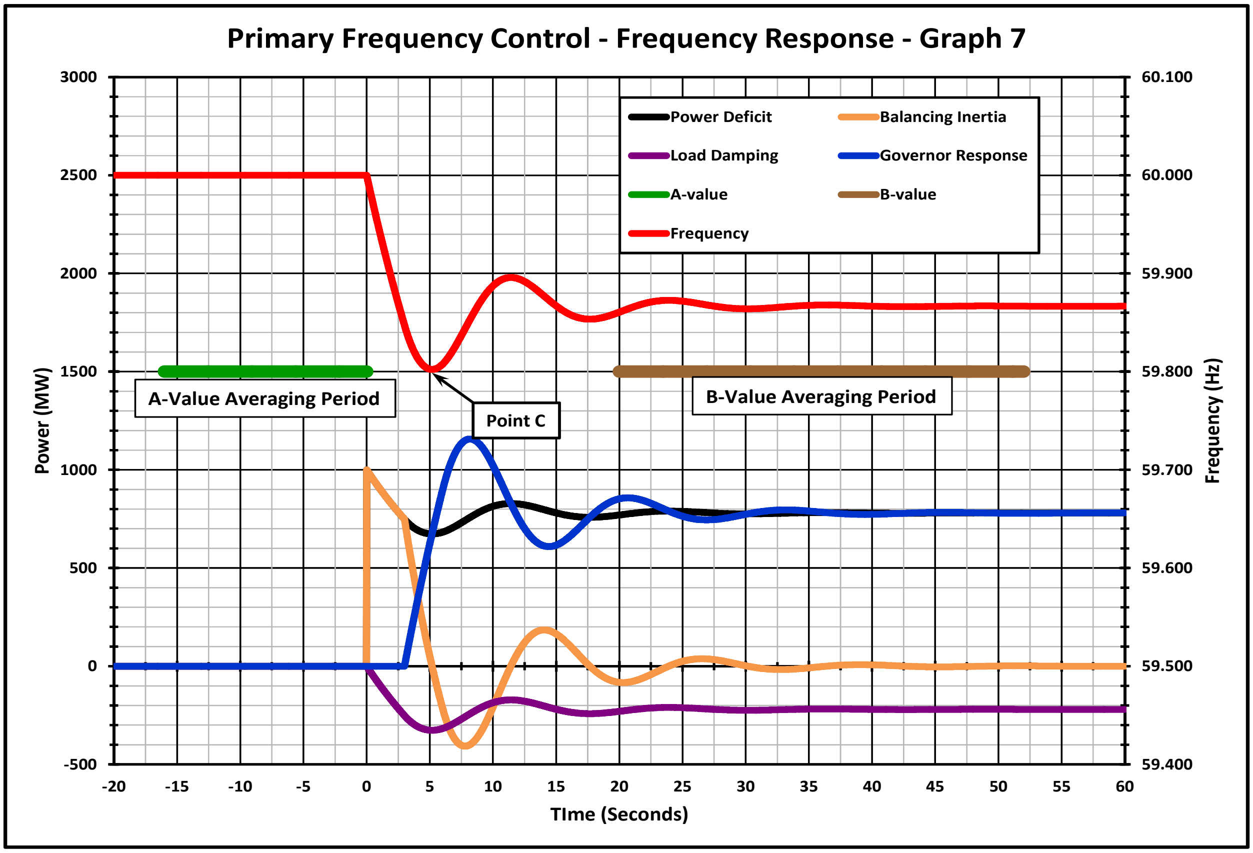
Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.



The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this settled period is called the "Settled Frequency Response." The Settled Frequency Response is the best measure to use as an estimator for the "Frequency Bias Setting" discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

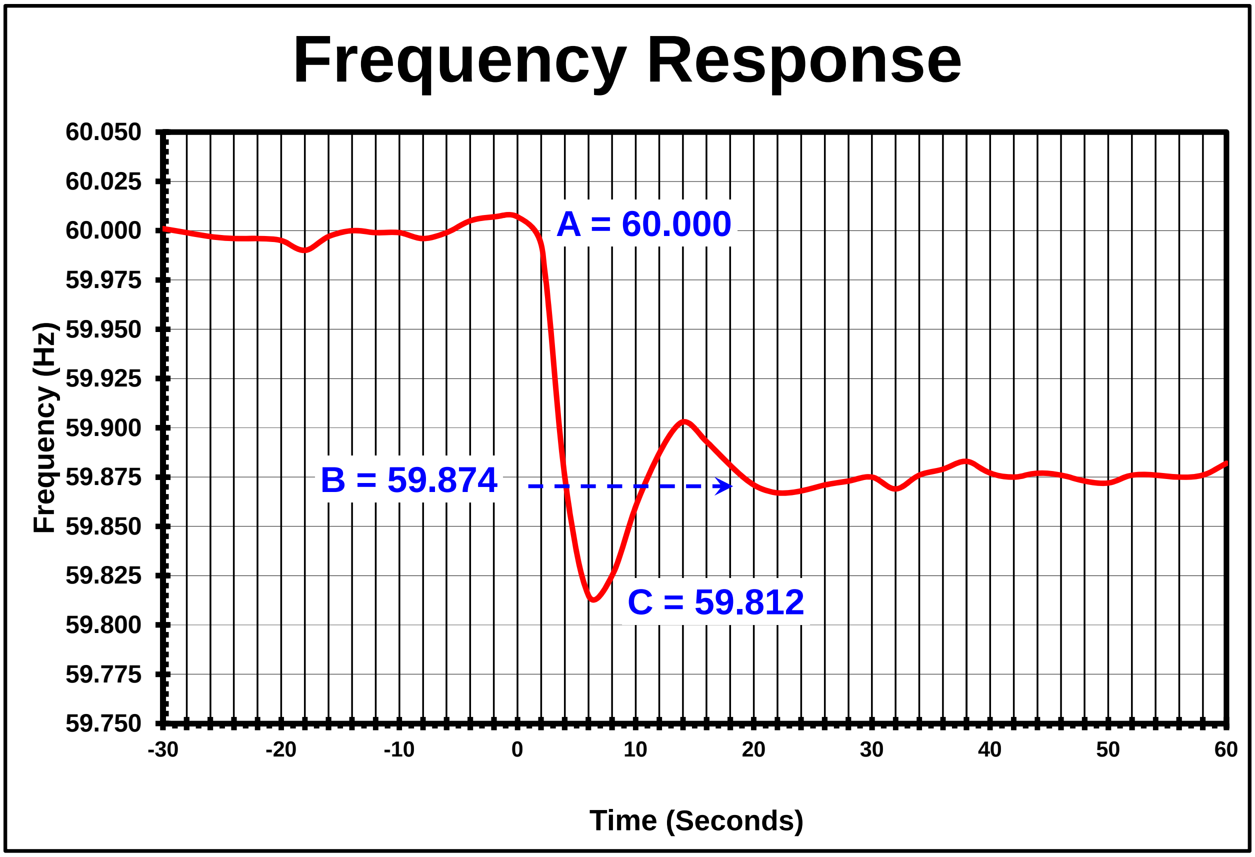


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas (“ERCOT”) and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation			
Scan Rate	**T 0 Scan**	**A Value (average)**	**B Value (average)**
6-Seconds	**Identify first significant change in frequency as the T 0 scan**	**Average of T-1 through T-2 scans**	**Average of T+4 through T+8 scans**
5-Seconds		**Average of T-1 through T-2 scans**	**Average of T+5 through T+10 scans**
4-Seconds		**Average of T-1 through T-3 scans**	**Average of T+6 through T+12 scans**
3-Seconds		**Average of T-1 through T-5 scans**	**Average of T+7 through T+17 scans**
2-Seconds		**Average of T-1 through T-8 scans**	**Average of T+10 through T+26 scans**

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

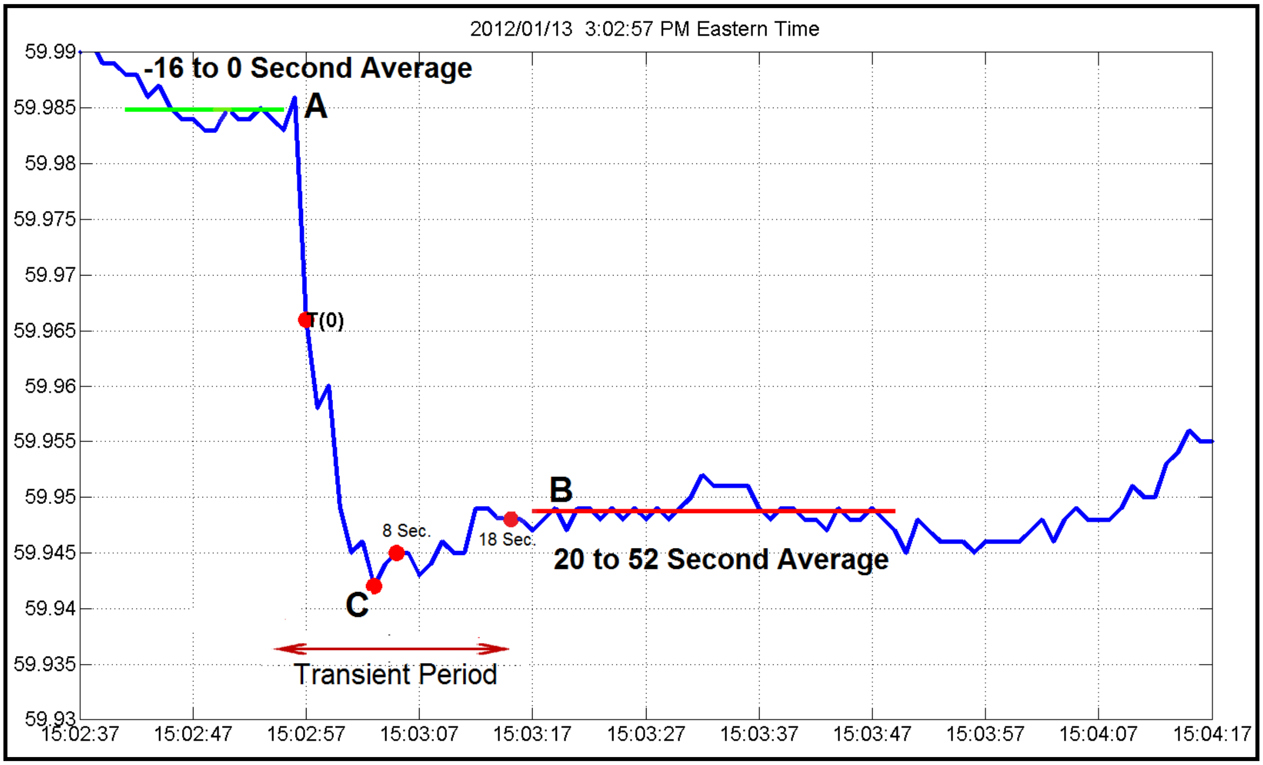


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named “**arrested frequency response.”** This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.

    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.
3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband

4. **Bi-directional** – the response occurs to both increases and decreases in frequency

5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)

6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value

This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response, the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of "real time pricing" and "dynamic pricing". If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual Gen_{BA} is the annual “Net Generation (MWh)”, FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual Load_{BA} is the annual “Net Energy for Load (MWh)”, FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection’s FRO by their share of Interconnection Bias. The data used for this calculation should be for the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection’s Frequency Response Obligation:

- Largest category C loss-of-resource (N-2) event.
- Largest total generating plant with common voltage switchyard.
- Largest loss of generation in the interconnection in the last 10 years.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of its net actual interchange on its tie lines with its adjacent Balancing Authorities divided by the change in interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their net actual interchange values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

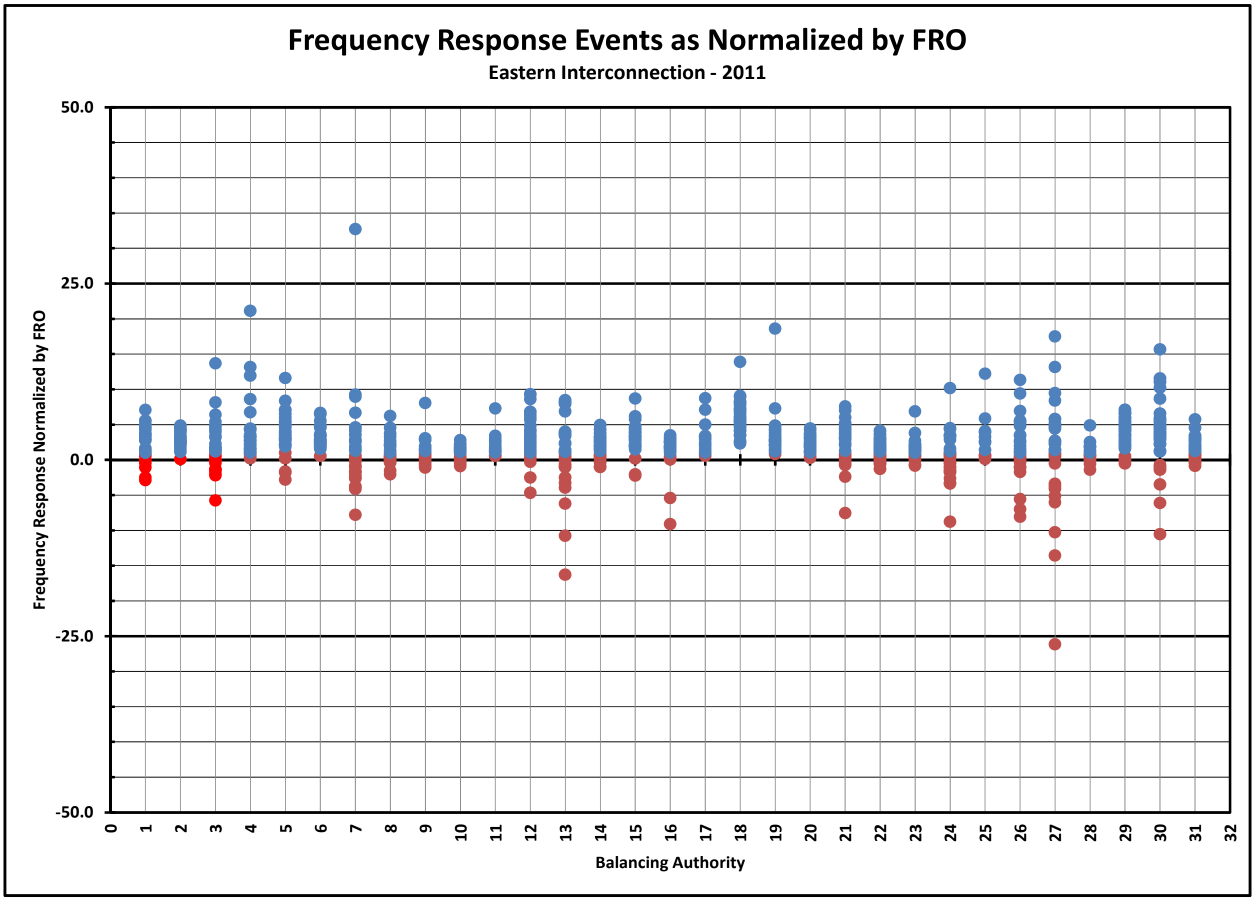
Single Event Frequency Response Data[8]

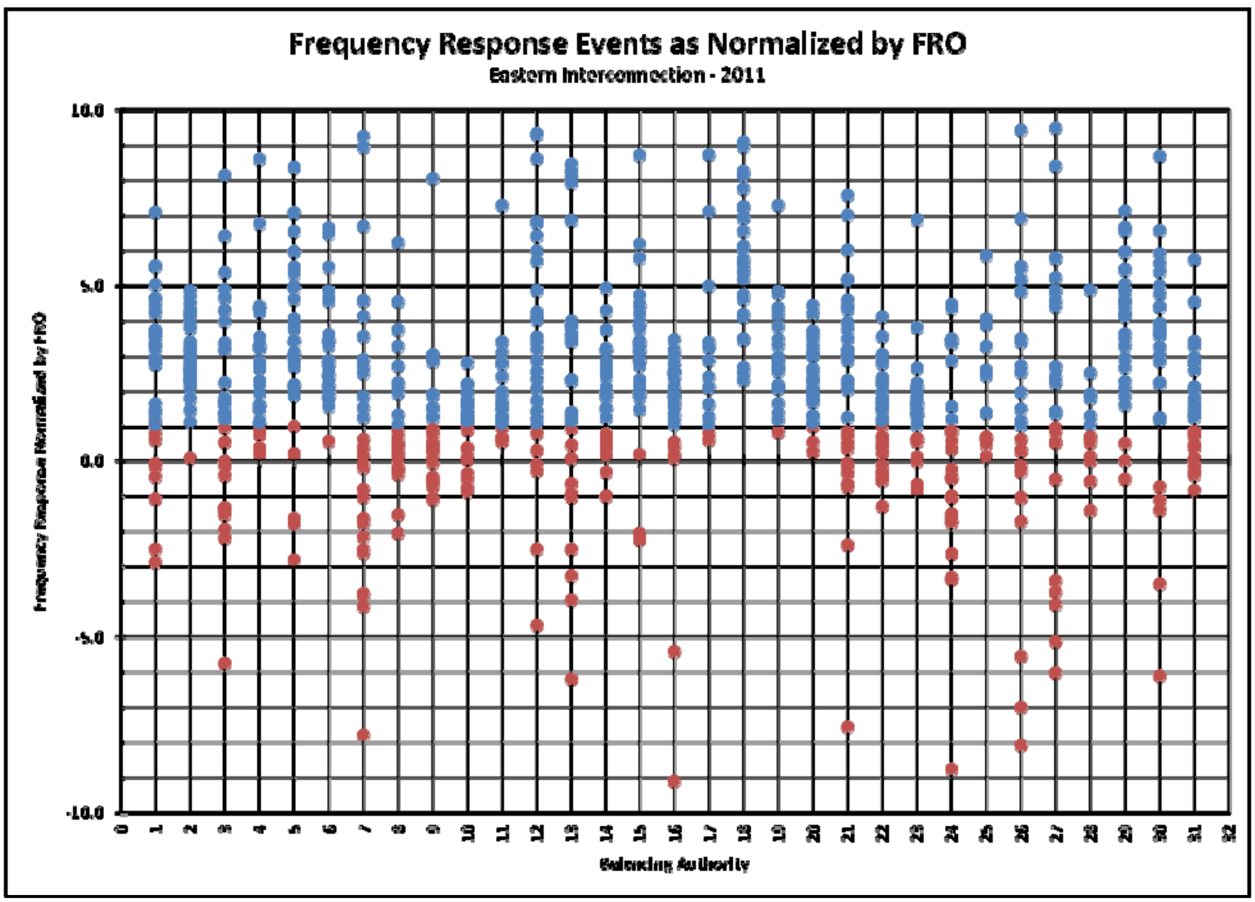
The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

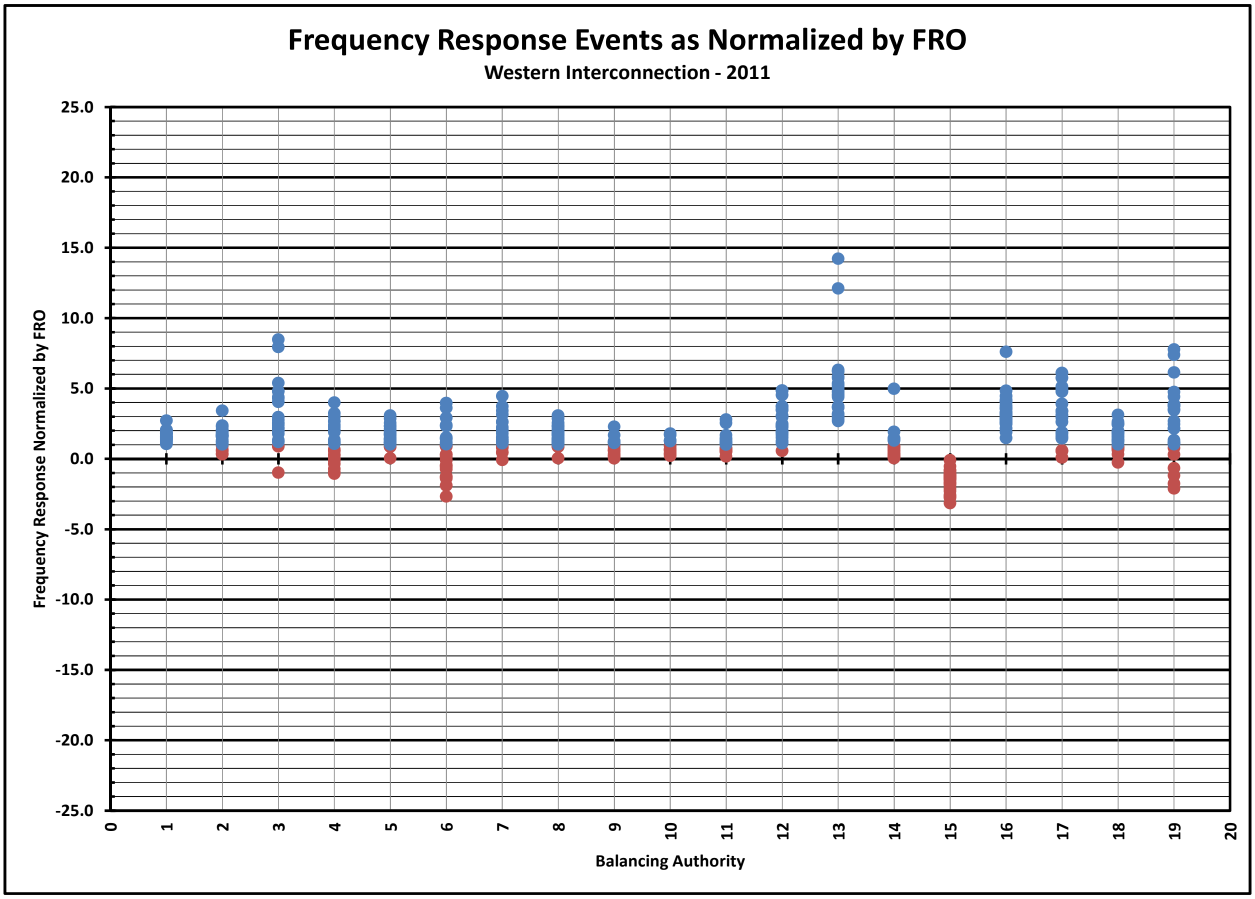
Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

[8] Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
50.0
25.0
0.0
-25.0
-50.0
Frequency Response Normalized by FRO
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
Balancing Authority


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
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19
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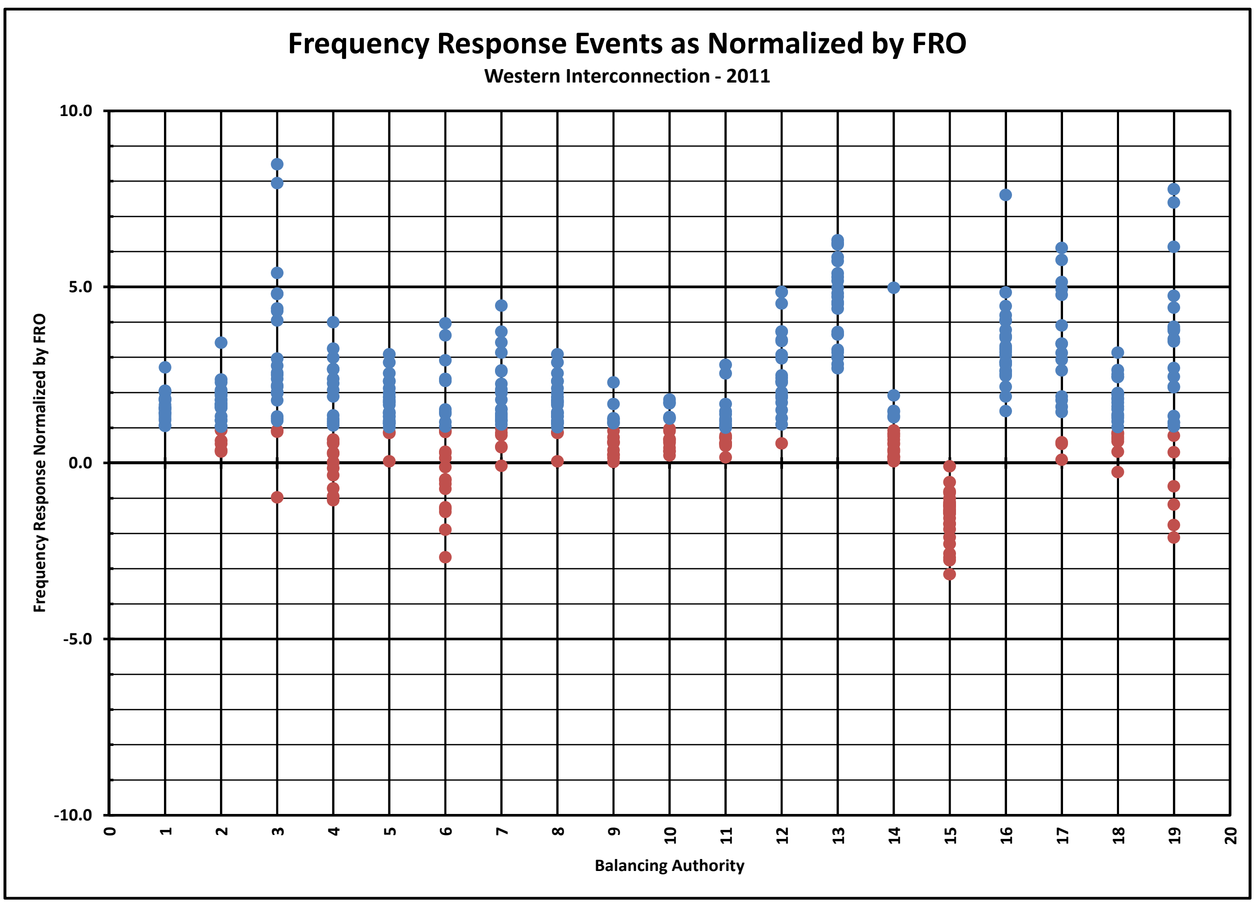
Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority
10.0
5.0
0.0
-5.0
-10.0
0
1
2
3
4
5
6
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Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a "false positive" compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.

- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either:

- *The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or*
- *The Frequency Bias Setting as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale
This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is <u>providing</u> Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities <u>receiving</u> Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error.

Exhibit E

Implementation Plan for Reliability Standard Submitted for Approval

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for BAL-003-1 – Frequency Response & Frequency Bias Setting Standard

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

Modified Standards

BAL-003-0.1b should be retired midnight of the day immediately prior to the Effective Date of Requirements R2, R3 and R4 of BAL-003-1 in the Jurisdiction in which the new standard is becoming effective.

New or Modified Definitions

The following definitions shall become effective when BAL-003-1 Requirements R2, R3, R4 and R5 become effective:

Frequency Response Measure (FRM): The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.

Frequency Response Obligation (FRO): The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Frequency Bias Setting: 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's inverse Frequency Response contribution to the Interconnection, and discourage withdrawal through secondary control systems.

Frequency Response Sharing Group (FRSG)[1]: A group, whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.

[1] This term and definition is identical to the definition in BAL-012-1 proposed standard.

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The existing definition of Frequency Bias Setting should be retired midnight of the day immediately prior to the Effective Date of Requirements R2, R3 and R4 of BAL-003-1 in the Jurisdiction in which the new standard is becoming effective.

The proposed revised definition for "Frequency Bias Setting" is incorporated in the following NERC approved standards:

- BAL-001-0.1a Real Power Balancing Control Performance
- BAL-004-0 Time Error Correction
- BAL-004-1 Time Error Correction
- BAL-005-0.1b Automatic Generation Control

Compliance with Standards

Once this standard becomes effective, the responsible entities identified in the applicability section of the standard must comply with the requirements. These include:

- Balancing Authorities
- Frequency Response Sharing Groups

Proposed Effective Date

Compliance with BAL-003-1 shall be implemented over a two-year period, as follows:

- In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.
- In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.
- Requirement R1 cannot be implemented prior to the addition of Frequency Response Sharing Group to the Compliance Registry.

Exhibit F

Frequency Response Initiative Report

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response Initiative Report

The Reliability Role of Frequency Response

October 30, 2012

RELIABILITY | ACCOUNTABILITY

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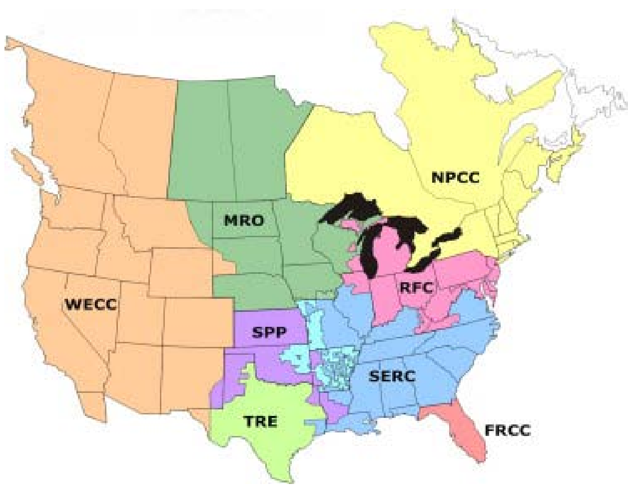
NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. ERO activities in Canada related to the reliability of the bulk power system are recognized and overseen by the appropriate governmental authorities in that country.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load-serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro that makes reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

This report was approved by the Planning Committee October 4, 2012, via e-mail vote.

This report was accepted by the Operating Committee October 12, 2012, via e-mail vote.

Introduction

System planning and operations experts are anticipating significantly higher penetrations of renewable energy resources, most of which are electronically coupled to the grid. This presents some new and different technical challenges, particularly in the reduction of system inertia through the displacement of conventional generation resources during light load periods. Load management and other demand-side initiatives also continue to grow. Most importantly, a continued downward trend for frequency response over a number of years has raised concern that credible contingencies may result in frequency excursions that encroach on the first step of under-frequency load shedding (UFLS). Such large frequency excursions could also trigger undesirable reactions from frequency-sensitive smart grid loads and electronically coupled renewable resources. Taken together, it is clear that maintaining adequate frequency response for bulk power system reliability is becoming more important and complex. While the decline in frequency response has lessened in the last couple of years, it is important that the industry understands the growing complexities of frequency control and is ready with comprehensive strategies to stay ahead of any potential problems.

NERC has undertaken various activities over the past few years in an effort to understand the steady decline in frequency response, particularly in the Eastern Interconnection. While some significant insight has been gained and system-wide and technical improvements have been achieved in the Western Interconnection and ERCOT, a deeper and more dedicated effort is needed.

To comprehensively address the issues related to frequency response, NERC launched the Frequency Response Initiative in 2010. In addition to coordinating the myriad of efforts underway in standards development and performance analysis, the initiative includes performing in-depth analysis of interconnection-wide frequency response to achieve a better understanding of the factors influencing frequency performance across North America.

Basic objectives of the Frequency Response Initiative include:

- development of a clearer and more specific statement of frequency-related reliability factors, including better definitions for "ownership" of responsibility for frequency response;
- collection and provision of more granular frequency response data on and technical analyses of frequency-driven bulk power system events, including root cause analyses;
- metrics and benchmarks to improve frequency response performance tracking;
- increasing coordinated communication and outreach on the issue to include webinars and NERC alerts and to share lessons learned; and
- focused discussion on communication of emerging technology issues, including frequency-related effects caused by renewable energy integration, smart grid technology deployment, and new end-use technology.

In March 2011, the NERC Planning Committee tasked the Transmission Issues Subcommittee (TIS, now the System Analysis and Modeling Subcommittee (SAMS)) with determining what criteria should be used to decide the appropriate level of interconnection-wide frequency response needed for reliability. The TIS started with a body of work already underway by the Resources Subcommittee (RS) and the Frequency Working Group (FWG) of the Operating Committee, and the Frequency Responsive Reserve Standard Drafting Team (FRRSDT). The RS produced a position paper on frequency response outlining the method to translate a resource contingency criterion into an Interconnection Frequency Response Obligation (IFRO).

The report on IFRO was approved by the Planning Committee September 2011.[2] Since that time, numerous modifications and improvements have been made to the IFRO determination analysis and calculations. Those changes are reflected in the IFRO section of this report.

This report provides an overview of the work that has been done to date toward gaining understanding of frequency response. It is in support of NERC Standards Project 2007-12 Frequency Response, which is preparing a revised draft standard (BAL-003-1). That standard is intended to codify a Frequency Response Obligation and means for measuring the performance of the Balancing Authorities.

[2] http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf

Executive Summary

Recommendations

1. NERC should embark immediately on the development of a NERC Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability. That guideline should address appropriate parameters for the following:

   - Existing conventional generator fleet – In order to retain or regain frequency response capabilities of the existing generator fleet, adopt:
     - deadbands of ±16.67 mHz,
     - droop settings of 3%–5% depending on turbine type,
     - continuous, proportional (non-step) implementation of the response,
     - appropriate operating modes to provide frequency response, and
     - appropriate outer-loop controls modifications to avoid primary frequency response withdrawal at a plant level.
   - Other frequency-responsive resources – Augment existing generation response with fast-acting, electronically coupled frequency responsive resources, particularly for the arresting and rebound periods of a frequency event:
     - contractual high-speed demand-side response,
     - wind and photo-voltaic – particularly for over-frequency response,
     - storage – automatic high-speed energy retrieval and injection, and
     - variable-speed drives – non-critical, short-time load reduction.

2. Instead of using a fixed margin, the calculation of the Interconnection Frequency Response Obligations should use statistical analysis to determine the necessary margin.

3. The starting frequency for the calculation of IFROs should be the frequency 5% of the lower tail of samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event, as shown in table A.

Table A: Interconnection Frequency Variation Analysis (Hz)				
Value	Eastern	Western	ERCOT	Québec
Starting Frequency (F_{Start})	59.974	59.976	59.963	59.972

4. The recommended UFLS first-step limitations for IFRO calculations are listed in table B.

Table B: Low-frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.5[3]
Western	59.5
ERCOT	59.3
Québec	58.5

5. The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced to account for differences between the 1-second and sub-second data for Point C (frequency nadir) by a statistically determined adjustment as listed in table C. Sub-second measurements will more accurately detect Point C.

Table C: Analysis of 1-Second and Sub-Second Data for Point C (CC_{ADJ})				
Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec	0	N/A	N/A	N/A

6. The allowable change in frequency from the IFRO Starting Frequency should be adjusted by a statistically determined value to account for the differences between the Value B and the Point C for historical frequency events as listed in table D.

Table D: Analysis of B Value and Point C (CB_R)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[4]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec[5]	N/A	1		1.550

[3] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

[4] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

7. An adjustment should be made to the maximum allowable delta frequency to compensate for the predominant withdrawal of primary frequency response exhibited in an interconnection until such withdrawal is no longer exhibited in that interconnection.

8. The determination of the maximum delta frequencies should be calculated in accordance with the methods embodied in Table E – Determination of Maximum Delta Frequencies.

Table E: Determination of Maximum Delta Frequencies

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Minimum Frequency Limit	59.500	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}[6]	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R[7]	1.000[8]	1.625	1.377	1.550[9]	Hz
Delta Frequency (DF_{CBR})[10]	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}[11]	.018	N/A	N/A	N/A	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz

[5] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond) with a 0.05 Hz confidence interval. See the Adjustment for Differences between Value B and Point C section of this report for further details.

[6] Adjustment for the differences between 1-second and sub-second Point C observations for frequency events.

[7] Adjustment for the differences between Point C and Value B.

[8] CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[9] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 ms operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond).

[10] DF_{CC}/CB_R

[11] Adjustment for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

9. The Interconnection Frequency Response Obligations should be calculated as shown in Table F: Recommended IFROs.

Table F: Recommended IFROs

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR	–	300	1,400	–	MW
IFRO[12]	-1,002	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[13]	40.6%	71.2%	48.7%	23.9%	
% of Interconnection Load[14]	0.17%	0.56%	0.45%	0.50%	

10. NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW.

11. Trends in frequency response sustainability should be measured and tracked by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both the Point C and Value B.

12. Frequency response performance by Balancing Authorities should not be judged for compliance on a per-event basis.

13. Linear regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003-1 – Frequency Response.

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[12] IFRO =

[13] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[14] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

14. NERC and the Frequency Working Group should annually review the process for detection of frequency events and the method for calculating the A and B Values and Point C. The associated interconnection frequency event database, methods for calculating interconnection metrics on risks to reliability, the associated probabilities, and the calculation of the IFROs using updated data should also undergo review in an effort to improve the process. Throughout this process, NERC should strive to improve the quality and consistency of the data measurements.

15. NERC should address improving the level of understanding of the role of turbine governors through seminars and webinars, with educational materials available to the Generator Owners and Generator Operators on an ongoing basis.

16. When the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group (ERAG MMWG) completes its review of turbine governor modeling, a new light-load case should be developed, and the resource loss criterion for the Eastern Interconnection's IFRO should be re-simulated.

17. Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including the testing of large resource loss analysis for IFRO validation.

Findings

1. Analysis of data submitted by the Balancing Authorities during the field trial indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when based on data that has the large degree of variability demonstrated by the field trial.

2. Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20–25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority frequency response performance.

3. There is a strong positive correlation between Eastern Interconnection load and frequency response for the 2009–2011 events. On average, when interconnection load changes by 1,000 MW, frequency response changes by 3.5 MW/0.1Hz.

4. Pre-disturbance frequency (Value A) is a statistically significant contributor to the variability of frequency response for the Eastern Interconnection. The expected (mean of the sample) frequency response for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz based on data from 2009 through April 2012.

5. There is a statistically significant seasonal (summer/not summer) correlation to the variability of frequency response for the Eastern Interconnection. The expected frequency response for summer (June–August) frequency events is 2,598 MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events based on data from 2009 through April 2012.

6. The difference in average frequency response between on-peak events and off-peak events is not statistically significant for the Eastern Interconnection and could occur by chance.

Frequency Response Overview

To understand the role frequency response plays in system reliability, it is important to understand the different components of frequency control and the individual components of Primary Frequency Control (also known as frequency response). It is also important to understand how those individual components relate to each other.

Frequency Control

Frequency control can be divided into four overlapping windows of time:

Primary Frequency Control (frequency response) – Actions provided by the interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Control comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual Balancing Authority or its Reserve Sharing Group to correct the resource-load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary frequency response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net-zero effect on area control error (ACE). Examples of Tertiary Control include dispatching generation to serve native load, economic dispatch, dispatching generation to affect interchange, and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control – This includes small offsets to scheduled frequency to keep long-term average frequency at 60 Hz.

Primary Frequency Control – Primary Frequency Response

Primary Frequency Control, also known generally as primary frequency response, is the first stage of frequency control and is the response of resources and load to arrest local changes in frequency. Primary frequency response is automatic, is not driven by any centralized system, and begins within seconds after the frequency changes, rather than minutes. Different resources, loads, and systems provide primary frequency response with different response times, based on current system conditions such as total resource/load mix and characteristics.

The NERC Glossary of Terms defines Frequency Response[15] in two parts:

- **Equipment** – The ability of a system or elements of the system to react or respond to a change in system frequency.
- **System** – The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, frequency response is typically discussed in the context of a loss of generation.

NOTE: For purposes of this report, the term "frequency response" is considered to be the overall response measured between T+20 and T+52 seconds, as used in the BAL-003-1 draft standard.

Frequency Response Illustration

Many components are included within the defined frequency response. The following simplified example graphically illustrates those components of frequency response and how they react to changes in system frequency. The example is presented as an energy balance problem for the interconnection. It is not intended to be a treatise on governors or other turbine-generator controls or the internal machine dynamics associated with those control actions. For additional information on those topics, see the References on Rotating Machines section in Appendix L.

The example is based on an assumed disturbance event due to the sudden loss of 1,000 MW of generation. Although a large event is used to illustrate the response components, even small events can result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for frequency response.

The loss of generation is illustrated by the black power deficit line using the MW scale on the left. The interconnection frequency is illustrated in red, using the hertz (Hz) scale on the right. The interconnection frequency is assumed to be 60 Hz when the disturbance occurs.

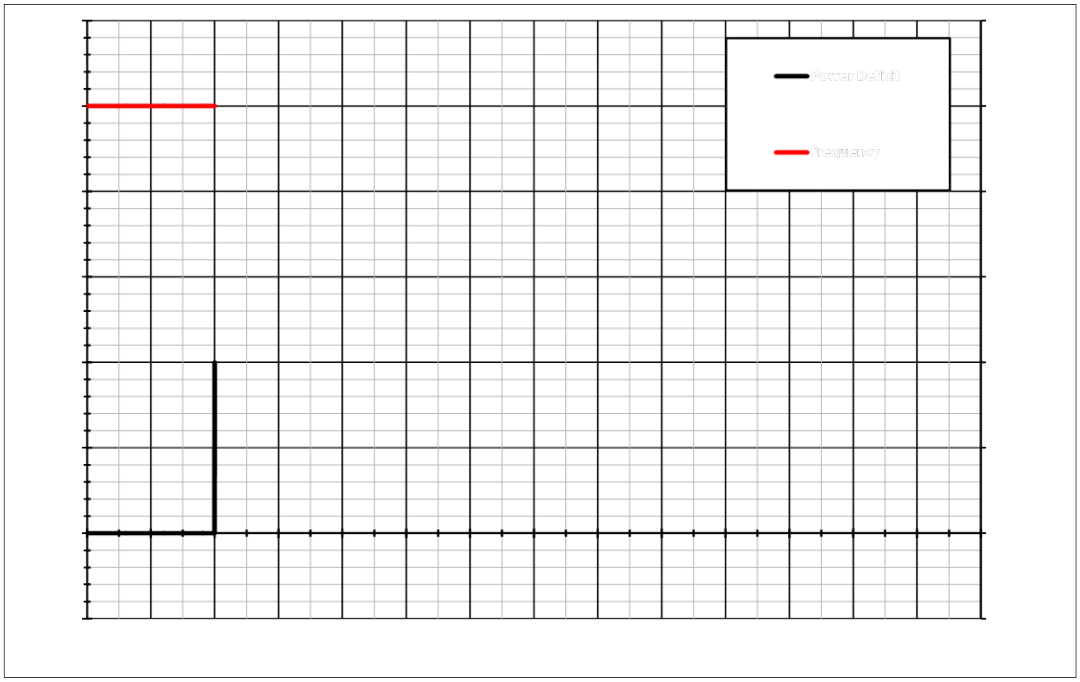
Figure 1 shows the tripping of a 1,000 MW generator. Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads across the system continue to use the same amount of power. The Law of Conservation of Energy[16] requires that the 1,000 MW must be supplied to the interconnection if the energy balance is to be conserved. That 1,000 MW of balancing power is provided by extracting it from the kinetic energy stored as inertial energy in the rotating mass of all of the synchronized turbine-generators and motors on the interconnection. It is produced by the slowing of the spinning inertial mass of rotating equipment on the interconnection that both releases the stored kinetic energy and reduces the frequency of the interconnection. The extracted energy

[15] Capitalized as referenced in the NERC Glossary of Terms; lowercased otherwise.

[16] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power—which is the first derivative of energy with respect to time—must also be conserved.

supplies the "balancing inertia"[17] power required to maintain the power and energy balance on the interconnection.

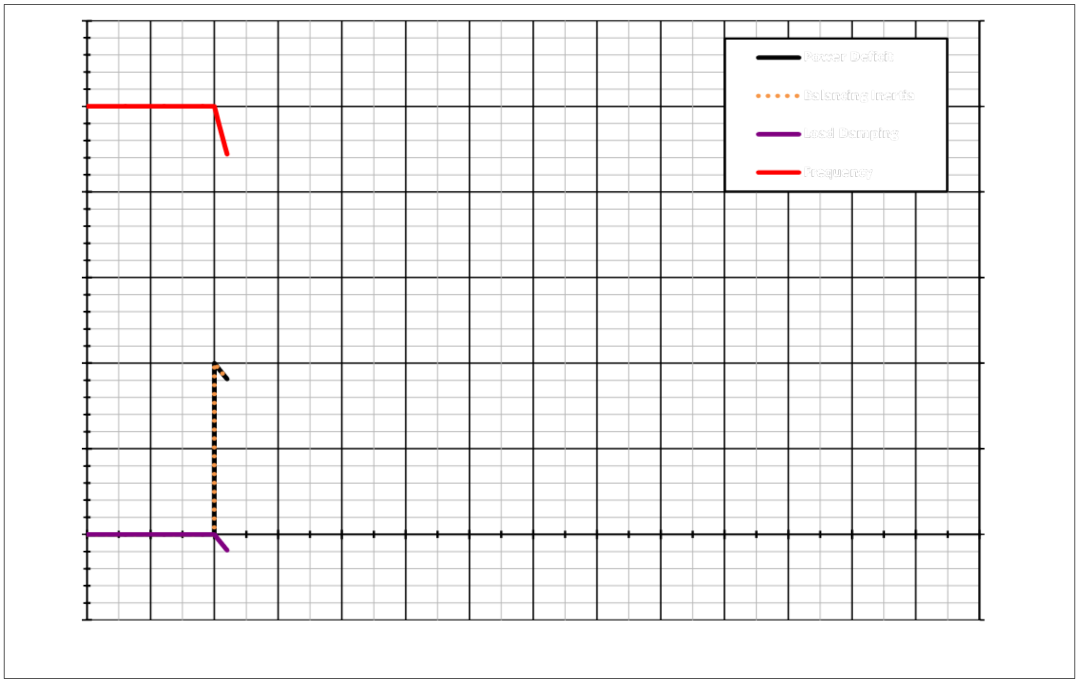
Figure 1: Loss of a 1,000 MW Generator



As this balancing power from inertia is used, the speed of the rotating equipment on the interconnection declines, resulting in a reduction of the interconnection frequency. Synchronously operated motors contribute to load damping; adjustable or variable speed drive motors are effectively decoupled from the interconnection frequency through their electronic controls, and they do not contribute to load damping. In general, any load that does not change with interconnection frequency (such as resistive loads) will not contribute to load damping or frequency response. The balancing inertia is illustrated in figure 2 by the orange dots, which represent the balancing inertia power that exactly overlays and offsets the power deficit. At this point in the example, no other energy injection has occurred through any governor control action.

[17] The term "balancing inertia" is coined here from the terms "inertial frequency response" and "balancing energy." Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response, and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

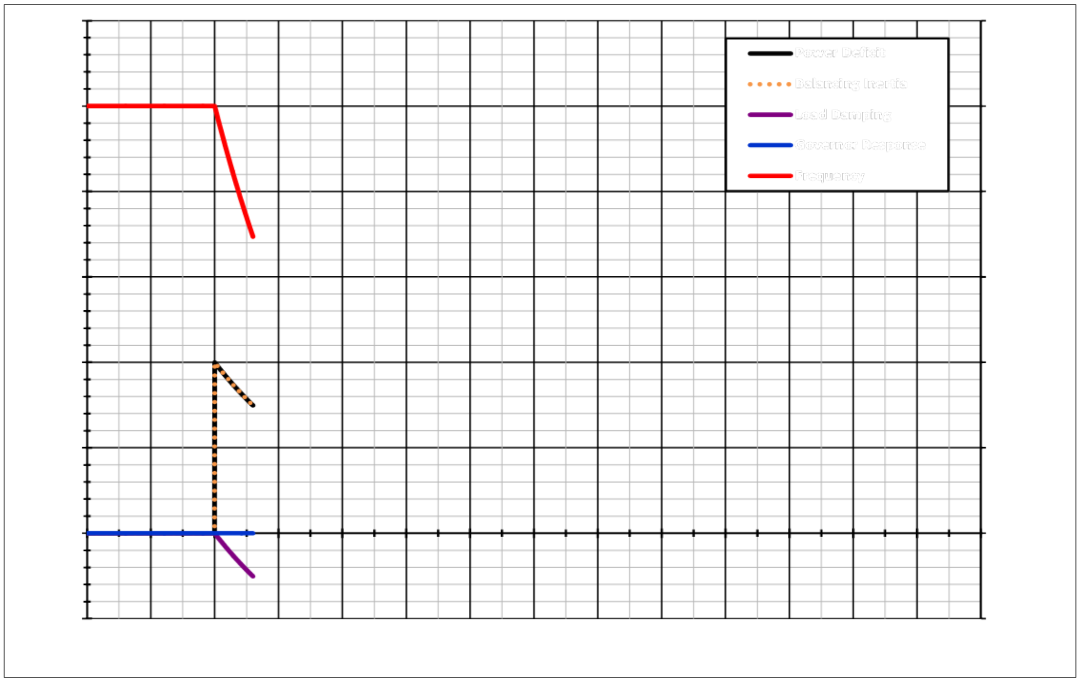
Figure 2: Inertial Energy Extracted from Rotating Mass of Generation and Synchronous Motor Load



As the rotating machines slow down (reflected as a decline of frequency), the generator governors, which are the controls that “govern” the speed of the generator turbines, sense this as a change in turbine speed. In this example, the change in frequency will be used to reflect this control parameter. Governor action then takes physical action, such as injecting more gas into a gas turbine, opening steam valves wider on a steam unit (also injecting more fuel into the boiler), or opening the control gates wider on a hydraulic turbine. This control action results in more combusted gases, steam, or water to impart more mechanical energy to the shaft of the turbine to increase its speed. The turbine shaft is coupled to the generator, where it is converted into additional electric energy. The process of the turbine slowing, the detection of change in speed, and the injection of additional mechanical energy is not instantaneous.

Until the additional mechanical energy can be injected, the frequency continues to decline, due to the ongoing extraction of balancing power from the inertial energy of the rotating turbine-generators and synchronous motors on the interconnection. As frequency continues to decline, the reduction in load also continues as the effect of load damping continues to reduce the load.

Figure 3: Time Delay of Governor Response

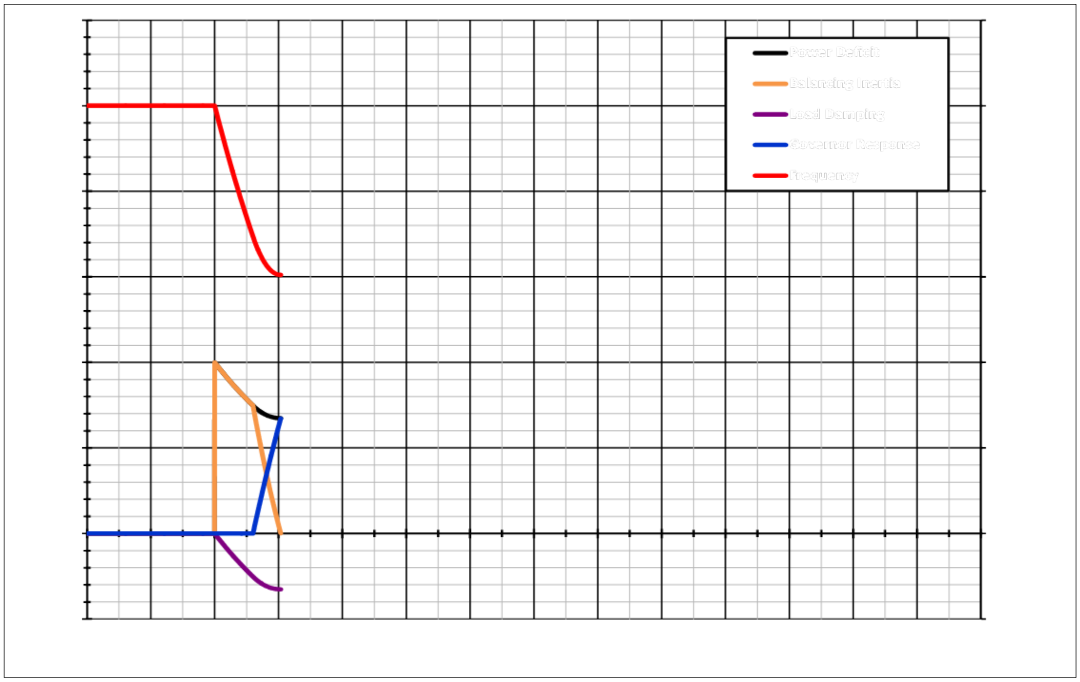


During the initial seconds of the disturbance event, the primary frequency response from the turbine governors has not yet influenced the frequency decline. For this example, primary frequency response from governors that injects additional energy into the system is reflected by the blue line (in MW) on figure 3.

After a short time delay, the governor response begins to increase rapidly in response to the initial decline in frequency, as illustrated in figure 4. In order to arrest the frequency decline, the governor response must offset the power deficit and replace the balancing power that had extracted inertial energy from the rotating machines of the interconnection. At this point in time, the balancing power from inertia is reduced to zero as it is replaced by the governor response. That replacement is shown as the crossing of the orange and blue lines in figure 4. The point at which the frequency decline is arrested is called the nadir, or Point C, and frequency response calculated to that point is “arrested frequency response.”

If the time delay associated with the delivery of governor response is reduced, the amount of balancing power from inertia required to limit the change in frequency for the disturbance event can also be reduced. This supports the conclusion that balancing power from inertia is required to manage the time delays associated with the delivery of primary frequency response. Not only is the rapid delivery of primary frequency response important, but so is the shortening of the time delay associated with its delivery.

Figure 4: Governor Response Replaces Balancing Power from Inertia and Arrests Frequency Decline



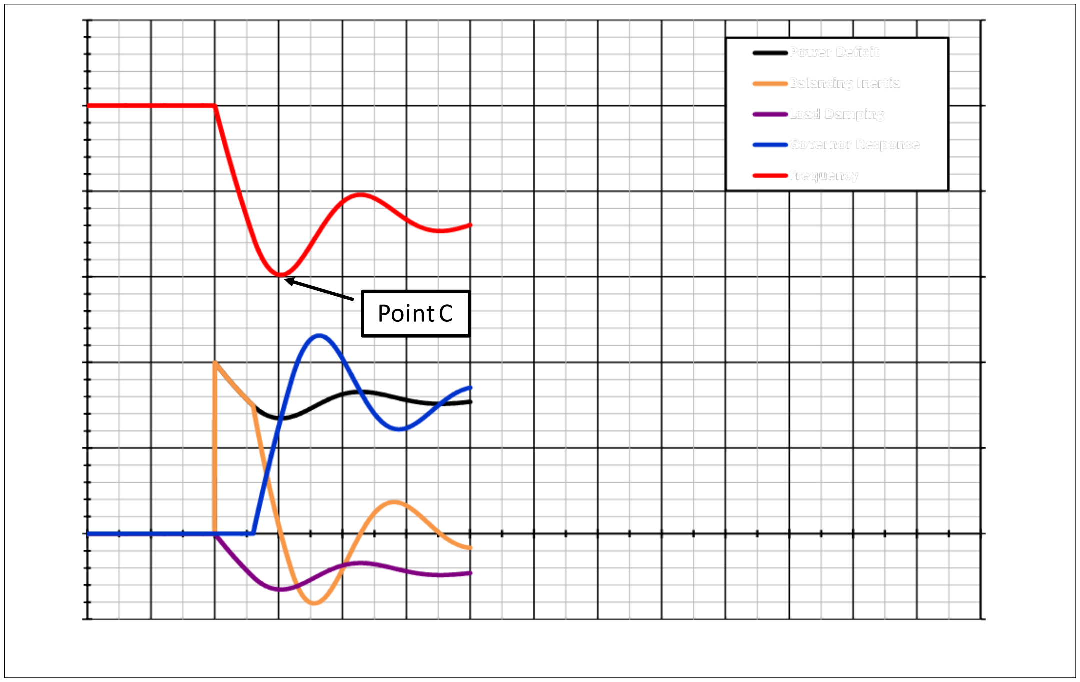
The above components are related to the length of time before the initial delivery of primary frequency response from governors begins and how much of the response is delivered before the frequency change is arrested.

From a system standpoint during this time delay, the amount of inertia on the interconnection, which determines the amount of energy available to be extracted from rotating machines, determines the slope of the frequency decline: the less inertia there is, the steeper the slope. This is important in the relationship between the balancing power from inertia and the time delay associated with the governor response. For a given time delay in primary frequency response from governors, the steeper the slope, the lower frequency will dip before it is arrested. Conversely, for a given balancing power from inertia and slope of frequency decline, the faster governor response can be provided, the sooner the frequency decline is arrested, making the nadir less severe.

Therefore, as traditional rotating generators are replaced by electronically coupled resources, such as wind turbines and solar voltaic resources (which provide less overall system inertia), the speed of delivery of governor response should increase, or other methods should be provided that support fast-acting energy injection to minimize the depth of frequency excursions.

The arrested frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a disturbance event. This minimum frequency is the frequency that is of concern from a reliability perspective. The goal is to arrest the frequency decline so frequency remains above the under-frequency load shedding (UFLS) relays with the highest settings so that load is not tripped. Frequency response delivered after frequency is arrested at this minimum provides less reliability value than frequency response delivered before Point C, but greater value than secondary frequency control power and energy that is delivered minutes later.

Figure 5: Post-Disturbance Transient Period (0 to 20 seconds)



Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with the governor action. This results in the frequency partially recovering from the minimum arrested value and results in some oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period, which typically ends around 20 seconds after start of the disturbance event. This post-disturbance transient period is shown in figure 5.

The total disturbance event is illustrated in figure 6. Frequency and power contributions stabilize at the end of the transient period. Frequency response calculated from data measured during this settled period is called the "settled frequency response." The settled frequency response is the measure used as an estimator for determining the Frequency Bias[18] setting used in the automated generator control (AGC) systems of the energy management systems (EMS) in energy control centers.

[18] As defined in the NERC Glossary: "A value, usually expressed in megawatts per 0.1 hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error."

Figure 6: Disturbance Event Frequency Excursion

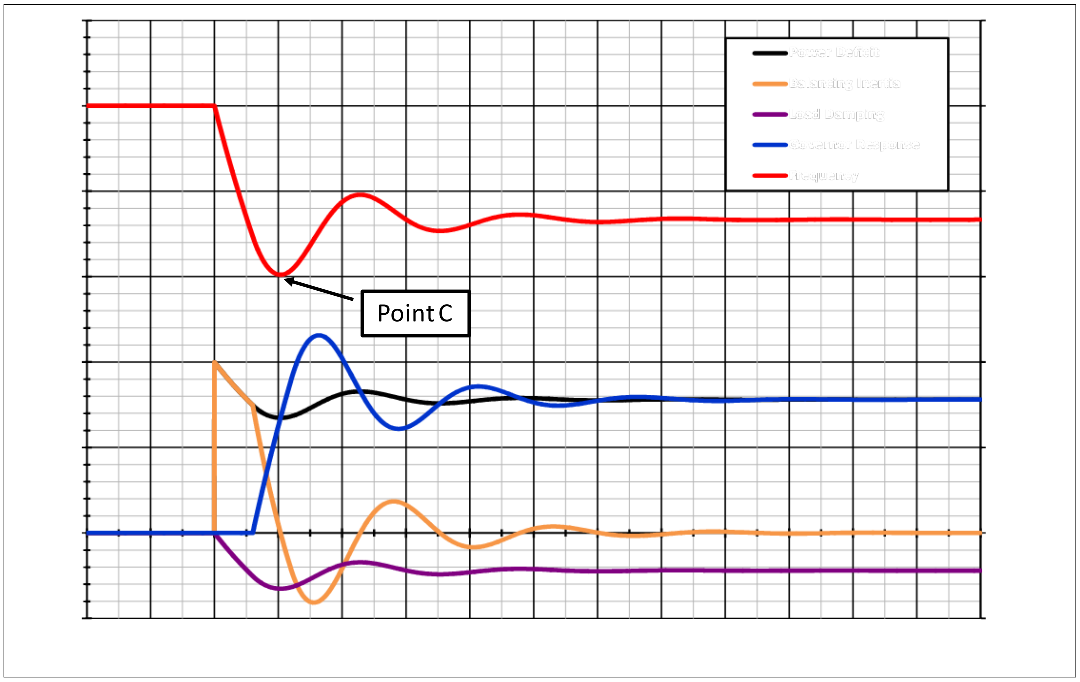


Figure 7: Averaging Periods used for Measuring Frequency Response

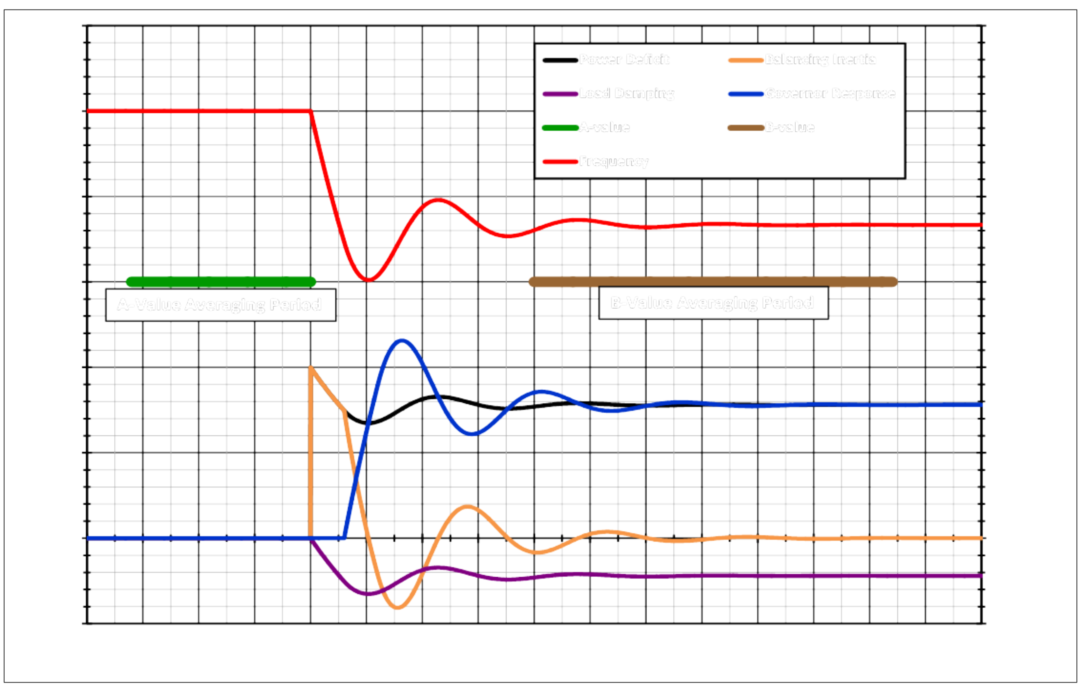


Figure 7 shows the averaging periods used to calculate[19] the pre-disturbance Value A frequency averaging period (T-16 through T+0 seconds) and the post-disturbance Value B frequency averaging period (T+20 through T+52 seconds) used to calculate the settled frequency response. The length of those periods is based on the length of the system control and data acquisition (SCADA) scan rates of the energy management systems (EMS) of the Balancing Authorities.

The calculation of the Value A and Value B frequencies began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second SCADA scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between Balancing Authorities with different scan rates.

The Value A frequency was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were then selected to be as consistent as possible with this 12-second average scan from the 6-second scan rate method. In addition, the "actual net interchange immediately before Disturbance" was then defined as the average of the same period and same scans as used for Value A averaging.

The Value B frequency was then selected to be an average as long as the average of 6-second scan data as possible, that would not begin until most of the hydro governor response had been delivered, and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "actual net interchange immediately after Disturbance" was then similarly defined as the average of the same period and same scans as used for the Value B.

Balancing Authority Frequency Response

Disturbances can cause the frequency to either increase from loss of load or decrease from loss of generation; frequency response characteristics of Balancing Authorities should be evaluated for both types of events.

Accurate measurement of frequency response for an interconnection or for individual Balancing Authorities is difficult unless the frequency deviation resulting from a system disturbance is significant. Therefore, it is better to analyze response only when significant frequency deviations occur.

Frequency response considers the following elements of an interconnected transmission system:

1. **Frequency Response Characteristic (FRC)** – For any change in generation/load balance in the interconnection, a frequency change occurs. Each Balancing Authority in the interconnection will respond to this frequency change through:
    - a load change that is proportional to the frequency change due to the load's FRC, and

[19] As proposed in Standard BAL-003-1 – Frequency Response.

- a generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the Balancing Authority's response to the frequency change; that is, its FRC. The combined response of all Balancing Authorities in the interconnection will cause the interconnection frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the Balancing Authority with the generation/load imbalance (referred to as the "Contingent Balancing Authority") corrects that imbalance, thus returning the interconnection frequency to its pre-disturbance value.

2. **Response to Internal and External Generation/Load Imbalances** – Most of a Balancing Authority's frequency response will be reflected in a change in its actual net interchange. By monitoring the frequency error (the difference between actual and scheduled frequency) and the difference between actual and scheduled interchange, using its response to frequency deviation, a Balancing Authority's automatic generation control (AGC) can determine whether the imbalance in load and generation is internal or external to its system. If internal, the Balancing Authority's AGC should correct the imbalance. If external, the Balancing Authority's AGC should allow its generator governors to continue responding (preserved by its frequency bias contribution in its ACE equation) until the contingent Balancing Authority corrects its imbalance, which should return frequency to its pre-disturbance value.

3. **Frequency Bias versus Frequency Response Characteristic (FRC)** – The Balancing Authority should set its bias setting in its AGC ACE equation to match its FRC. In doing so, the Balancing Authority's bias contribution term would exactly offset the tie line flow error (Ni_A – Ni_S) of the ACE that results from governor action following a frequency deviation on the interconnection. The following sections discuss the effects of bias settings on control action and explain the importance of setting the bias equal to the Balancing Authority's FRC. The discussion explains the control action on all Balancing Authorities external to the contingent Balancing Authority (the Balancing Authority that experienced the sudden generation/load imbalance) and on the contingent Balancing Authority itself.

   While this discussion deals with loss of generation, it applies equally to loss of load, or any sudden contingency resulting in a generation/load mismatch. Each Balancing Authority's frequency response will vary with each disturbance because generation and load characteristics change continuously. This discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero) just prior to the sudden generation/load imbalance.

4. **Effects of a Disturbance on all Balancing Authorities External to the Contingent Balancing Authority** – When a loss of generation occurs, an interconnection frequency error will occur as rotating kinetic energy from the generators of the interconnection is expended, slowing the generators throughout the interconnection. All Balancing Authorities' generator governors will respond to the frequency error and increase the

output of their generators (increase speed) accordingly. This will cause a change in the Balancing Authorities' actual net interchange. In other words, the Actual Net Interchange (Ni_A) will be greater than the Scheduled Net Interchange (Ni_S) for all but the contingent Balancing Authority, and the result is a positive flow out of the non-contingent Balancing Authorities. The resulting tie flow error ($Ni_A – Ni_S$) will be counted as Inadvertent Interchange.

If the Balancing Authorities were using only tie line flow error (i.e., flat tie control ignoring the frequency error), this non-zero ACE would cause their AGC to reduce generation until Ni_A was equal to Ni_S, returning their ACE to zero. However, doing this would not help arrest interconnection frequency decline, because the Balancing Authorities would not be helping to temporarily replace some of the generation deficiency in the interconnection. With the tie line bias method, the Balancing Authorities' AGC should allow their governors to continue responding to the frequency deviation until the contingent Balancing Authority replaces the generation it has lost.

In order for the AGC to allow governor action to continue to support frequency, a frequency bias contribution term is added to the ACE equation to counteract the tie flow error. This bias contribution term is equal in magnitude and opposite in direction to the governor action and should ideally be equal to each Balancing Authority's frequency response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error, the bias should exactly counteract the tie flow error portion of the ACE calculation, allowing the continued support of the generator governor action to support system frequency.

In other words, $BiasContributionTerm = 10B(f_A - f_S)$. ACE will be zero, and AGC will not read just generation.

The ACE equation is then:

$$ACE = (Ni_A - Ni_S) - 10B(f_A - f_S) - I_{ME}$$

Where:

- The factor 10 converts the bias setting (B) from MW/0.1 Hz to MW/Hz.
- I_{ME} is meter error correction estimate; this term should normally be very small or zero.

NOTE: Although frequency response and bias are often discussed as positive values (such as "our bias is 50 MW/0.1 Hz"), frequency response and bias are actually negative values.

If the bias setting is greater than the Balancing Authority's actual frequency response characteristic, then its AGC will increase generation beyond the primary frequency response from governors, which further helps arrest the frequency decline, but increases Inadvertent Interchange. Likewise, if the bias contribution term is less than the actual FRC, its AGC will reduce generation, reducing the Balancing Authority's contribution to arresting the frequency change. In both cases, the resultant control action is unwanted.

5. **Effects of a Disturbance on the Contingent Balancing Authority** – In the contingent Balancing Authority where the generation deficiency occurred, most of the replacement power comes from the interconnection over its tie lines from the frequency response contributions of the other Balancing Authorities in the interconnection. A small portion will be made up internally from the contingent Balancing Authority's own governor response. In this case, the difference between Ni_A and Ni_S for the contingent Balancing Authority is much greater than its frequency bias component. Its ACE will be negative (if the loss is generation), and its AGC will begin to increase generation.

   - Ni_A – drops by the total generation lost less the contingent Balancing Authority's own primary frequency response from governors
   - Ni_S – does not change

   The contingent Balancing Authority must take appropriate steps to reduce its ACE to zero or pre-disturbance ACE if ACE is negative within 15 minutes of the contingency. (Reference: formerly Operating Criterion II.A.) The energy supplied from the interconnection is posted to the contingent Balancing Authority's inadvertent balance.

6. **Effects of a Disturbance on the Contingent Balancing Authority with a Jointly Owned Unit** – In the contingent Balancing Authority where the generation deficiency occurred on a jointly owned unit (with dynamically scheduled shares being exported), the effect on the tie line component (Ni_A – Ni_S) of their ACE equation is more complicated. The Ni_A drops by the total amount of the generator lost, while the Ni_S is reduced only by the dynamic reduction in the shares being exported.

   - Ni_A – drops by the total generation lost less the contingent Balancing Authority's own primary frequency response from governors
   - Ni_S – decreases by the reduction in dynamic shares being exported

   The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the interconnection.

7. **Effects of a Disturbance on the Non-contingent Balancing Authority with a Jointly Owned Unit** – In the non-contingent Balancing Authority where the generation deficiency occurred on a jointly-owned unit in another Balancing Authority (with dynamically scheduled shares being exported), the effect on the tie line component (Ni_A – Ni_S) of their ACE equation is also complicated. The Ni_A increases by the Balancing Authority's own primary frequency response from governors, while the Ni_S is reduced only by the dynamic reduction in the shares being imported.

- Ni_A – increases by the Balancing Authority's own primary frequency response from governors
- Ni_S – decreases by withdrawn dynamic shares of the jointly-owned unit

The net effect is that the tie line bias component only reflects the contingent Balancing Authority's share of the lost generation. Most of the replacement power comes from the interconnection over its tie lines from the frequency bias contributions of the other Balancing Authorities in the interconnection.

Historical Frequency Response Analysis

History of Frequency Response and its Decline

Interconnection frequency response has been a subject of industry interest and attention since the first two electric systems became interconnected and the concept of frequency bias was adopted. In 1942, the first test to determine the system's load/frequency characteristic was conducted for use in setting bias control. As interconnected systems grew larger and the characteristics of load and generation changed, it became apparent that guidelines were needed regarding frequency response to avoid one system imposing undue frequency regulation burdens on its interconnected neighbors. During the 1970s and 1980s, NERC's Performance Subcommittee (now the Resources Subcommittee of the Operating Committee), which is charged with monitoring the control performance of the interconnections, observed that generators' governor responses to frequency deviations had been decreasing, especially in the Eastern Interconnection. The result was quite noticeable during large generation losses where the frequency deviation was not arrested as quickly as it once was. The industry did not initially recognize that power systems operations could significantly influence primary frequency response.[20]

In 1991, NERC's Performance Subcommittee approached the Electric Power Research Institute (EPRI) with a request to fund and manage a study of the apparent decline in governor response in the interconnections. EPRI agreed and in turn contracted with EPIC Engineering to perform this study. The conclusions were captured in a joint EPRI/NERC report, "Impacts of Governor Response Changes on the Security of North American Interconnections."[21] These studies indicated that the frequency response of the interconnections was declining at rates greater than would be expected with the growth of demand and generating capacity.[22] Although frequency response was declining, the opinion of experts at the time was that the decline had not reached a point at which reliability was being compromised.

The NERC Resources Subcommittee proposed a frequency response standard for comment in 2001. In response to these comments, the Frequency Task Force of the NERC Resources Subcommittee published a Frequency Response Standard white paper[23] intended to create an understanding of the need for a frequency response standard and the technical and economic drivers motivating its development. The paper documented and discussed the decline observed in frequency response in the Eastern and Western Interconnections.

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[20] *See* Illian, H.F. *Frequency Control Performance Measurement and Requirements*, LBNL-4145E (December 2010).

[21] EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992.

[22] *See* EPRI Report TR-101080, *Impacts of Governor Response Changes on the Security of North American Interconnections*, October 1992 ("An analysis of the 14 Frequency Response Characteristics Surveys conducted by NERC over the 1971 to 1993 period showed that the Frequency Response in percent MW/O. 1Hz has deteriorated. This value in 1971 was between 2.25 and 3.25% (depending on the area) and by 1993 had dropped to 0.75 and 1.25 %.").

[23] Available here: http://www.nerc.com/docs/oc/rs/Frequency_Response_White_Paper.pdf ("Frequency Response Standard Whitepaper").

Projections of Frequency Response Decline

In August 2011, the Transmission Issues Subcommittee[24] of the NERC Planning Committee completed an analysis titled "Interconnection Criteria for Frequency Response Requirements – Determination of Interconnection Frequency Response Obligations."[25] The analysis included comparisons of various Resource Contingency Protection Criteria for loss of resources, including largest potential loss-of-resource event (N-2), the largest total generating plant with common voltage switchyard, and the largest loss of generation in the interconnection in the last 10 years. Also examined in that analysis were the various other factors that must be considered in an IFRO determination: the highest under-frequency load shedding (UFLS) program setpoint within each interconnection, special consideration of demand-side frequency responsive programs in ERCOT, and a reliability margin to account for the variability of frequency due to items such as time error correction (TEC), variability of load, variability of interchange, variability of frequency over the course of a normal day, and other uncertainties. The proposed margin was analyzed using a probabilistic approach based on 1-minute frequency performance data for each interconnection. The Transmission Issues Subcommittee recommended the following IFROs for the four interconnections: Eastern: -1,875 MW/0.1 Hz; Western: -637 MW/0.1 Hz; Texas: -327 MW/0.1 Hz; and Québec: -113 MW/0.1 Hz. The Transmission Issues Subcommittee IFRO report was approved by the NERC Planning Committee in September 2011 and forwarded to the Standard Drafting Team for their consideration.

A similar report had been prepared by the Resources Subcommittee of the NERC Operating Committee in January 2011 titled "NERC Resources Subcommittee Position Paper on Frequency Response."[26] That report used similar Resource Contingency Protection Criteria but used the prevalent 59.5 Hz highest UFLS setpoint for the Eastern Interconnection and a lower 59.3 Hz UFLS setpoint for ERCOT. The Resources Subcommittee analysis also used a 25% reliability margin for all four interconnections. The Resources Subcommittee recommended the following IFROs for the four interconnections: Eastern: -1,406MW/0.1 Hz; Western: -685 MW/0.1 Hz; Texas: -286 MW/0.1 Hz; and Québec: -141 MW/0.1 Hz. The Resources Subcommittee position paper was approved by the Operating Committee in March 2011 and was considered by the Frequency Response Standard Drafting Team. NERC has been tracking the decline of frequency response in the Eastern Interconnection for several years.

[24] The Transmission Issues Subcommittee is now the System Analysis and Modeling Subcommittee (SAMS).

[25] Available here: http://www.nerc.com/docs/pc/tis/Agenda_Item_5.d_Draft_TIS_IFRO_Criteria%20Rev_Final.pdf.

[26] Available here: http://www.nerc.com/docs/oc/rs/NERC%20RS%20Position%20Paper%20on%20Frequency%20Response%20Final%20(May%2027%202011).pdf.

Figure 8: Eastern Interconnection Mean Primary Frequency Response[27] (March 30, 2012)

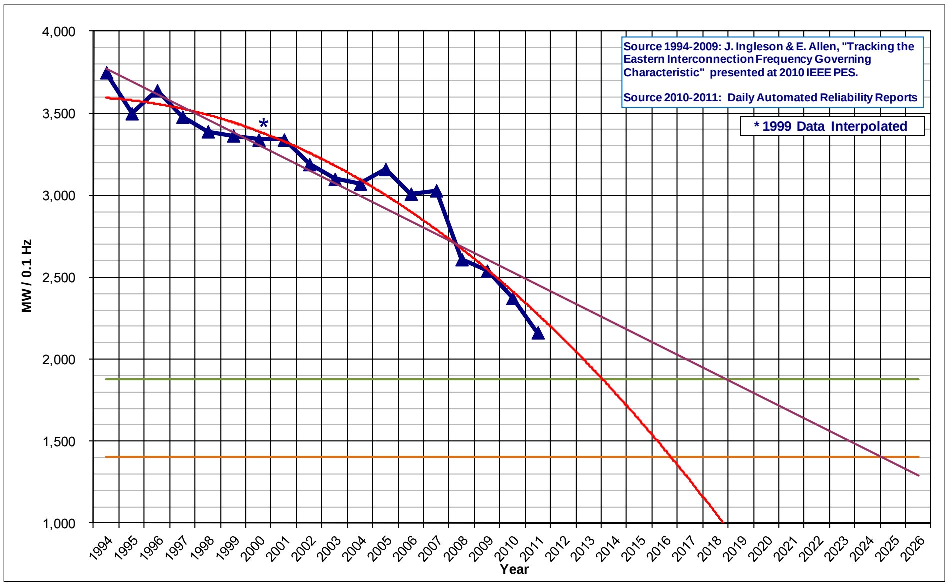


Figure 8 shows how frequency response has declined since 1994, as filed in NERC's "Motion for an Extension of Time of the North American Electric Reliability Corporation" (for the development of Standard BAL-003-1 – Frequency Response).[28] That request for extension of time was granted by FERC in its Order on Motion for an Extension of Time and Setting Compliance Schedule (Issued May 4, 2012).[29]

Comparing the proposed IFROs from those two studies, the Eastern Interconnection IFROs range from about 1,400 MW/0.1 Hz to about 1,900 MW/0.1 Hz, and the linear projection of the frequency response decline intercepts those target IFROs between 2019 and 2024. Even the more pessimistic polynomial projection of the decline intercepts the proposed IFROs between 2014 and 2016. This shows that there was still some time as of that filing for revising BAL-003-1 and responding to the decline in frequency response.

Figure 8 was revised shortly after the March 2012 filing in conjunction with revised frequency response calculation methods used in NERC's 2012 State of Reliability report (May 2012). Figure 9 reflects the revised frequency response calculations for 2009 through 2011.

[27] The Frequency Response data from 1994 through 2009 displayed in figure 2 is from a report by J. Ingleson & E. Allen, Tracking the Eastern Interconnection Frequency Governing Characteristic that was presented at the 2010 IEEE.

[28] Filing available at: http://www.nerc.com/files/MotionExtTime_RM06-16_03302012.pdf

[29] Order available at: http://www.nerc.com/files/Order_Motion_Extension_Time_Compliance_Sched_2012.5.4.pdf

Figure 9: Updated Eastern Interconnection Mean Primary Frequency Response (May 2012)

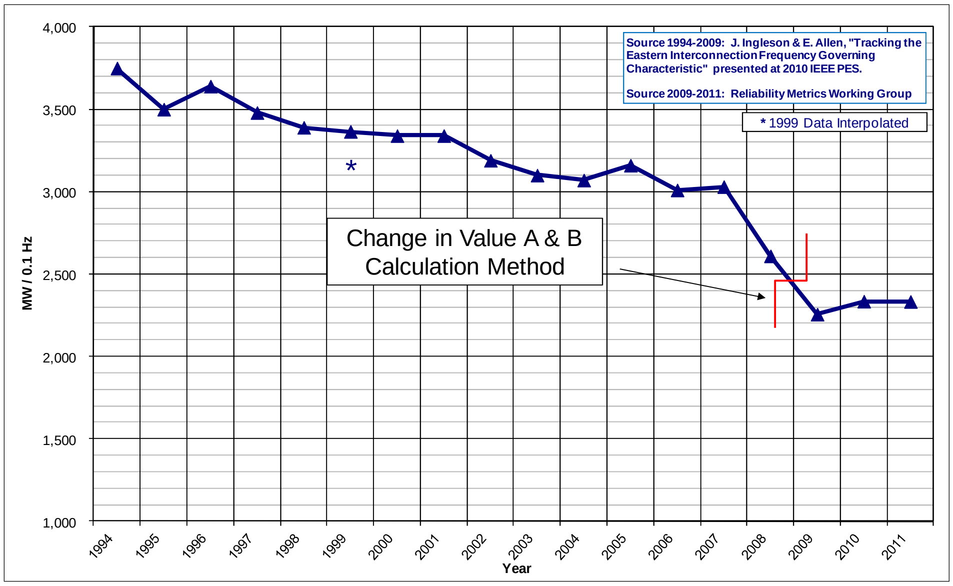


Figure 9 shows an improvement in frequency response in 2009 through 2011 due to alignment of the methods for calculation Values A and B. That method is consistent with the method being proposed in NERC Standard BAL-003-1. The method has since been further refined, as reflected in the Statistical Analysis of Frequency Response section of this report.

Figures 10–13 show the statistical analysis of the frequency response for 2009–2011 for the Eastern, Western, and ERCOT Interconnections from the 2012 State of Reliability report in box plot format (only 2011 data was available for the Québec Interconnection).

Figure 10: Eastern Interconnection Frequency Response Analysis for 2009–2011

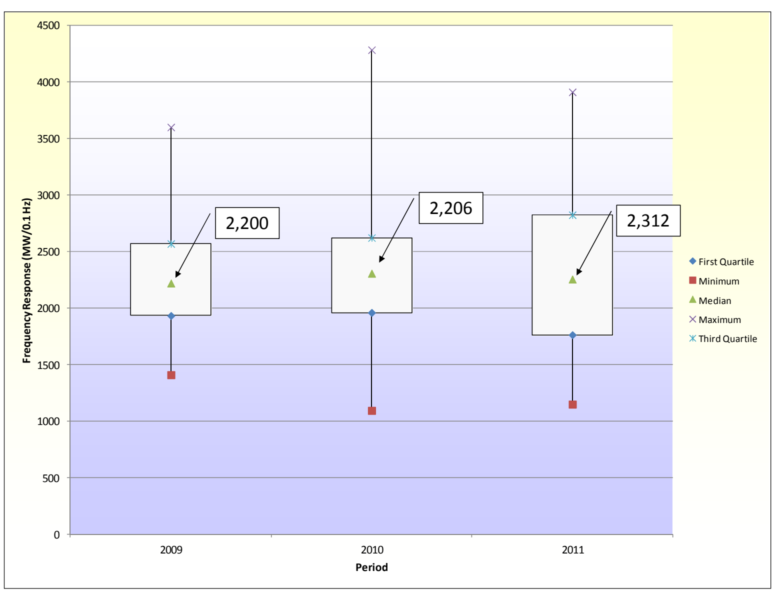


Figure 11: Western Interconnection Frequency Response Analysis for 2009–2011

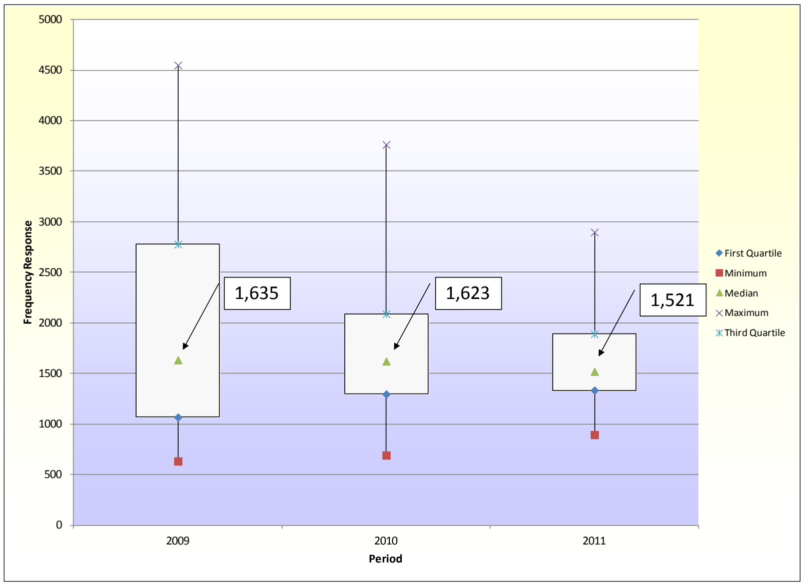
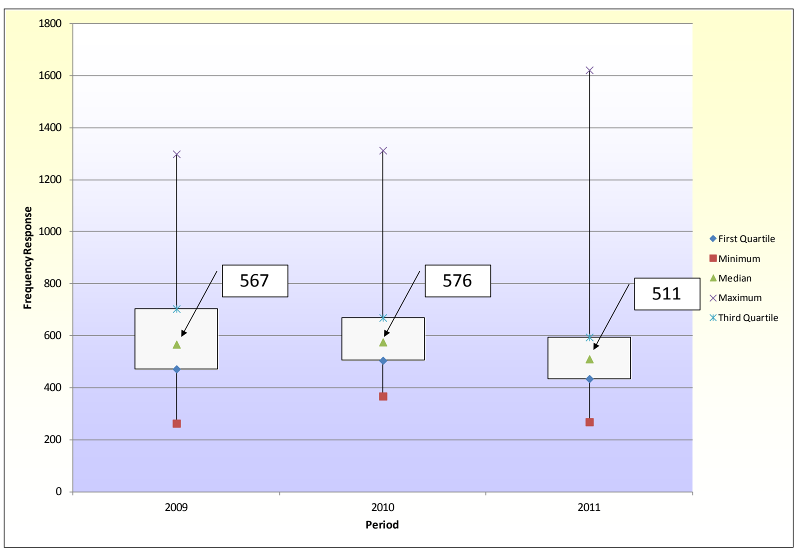
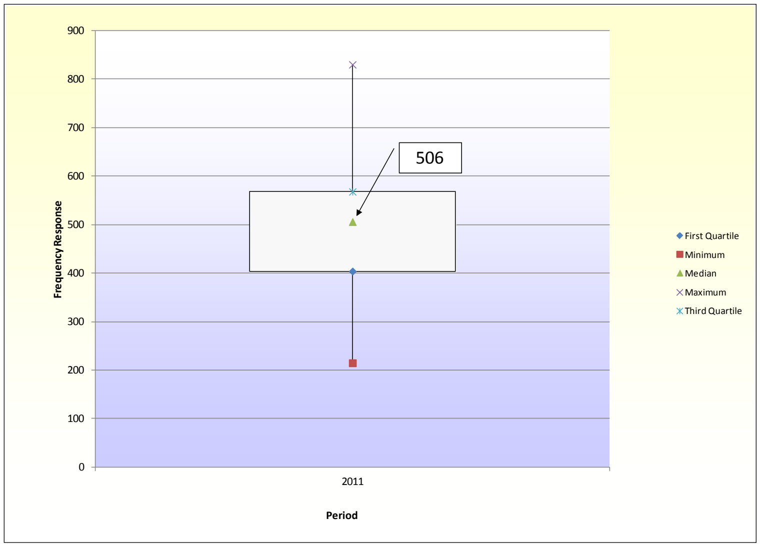


Figure 12: ERCOT Interconnection Frequency Response Analysis for 2009–2011



It is important to note the range of variability of the frequency response for each year. Additional events and modifications to the calculation methods for the A, B, and C values have been made since these values were calculated for the May 2012 report. The new values are reflected in the Statistical Analysis section of this report.

Figure 13: Québec Interconnection Frequency Response Analysis for 2011



Statistical Analysis of Frequency Response (Eastern Interconnection)

In July 2012, a statistical analysis of the frequency response of the Eastern Interconnection was performed for the calendar years 2009–2011 and the first three months of 2012. The size of the dataset was 163 (with 44 observations for 2009, 49 for 2010, 65 for 2011, and 5 for 2012).

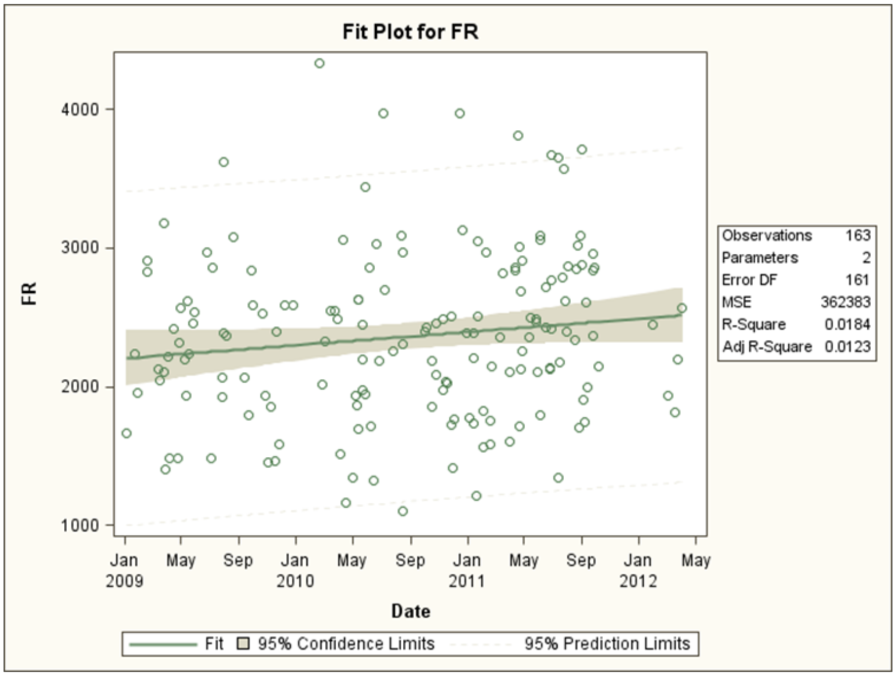
Table 1: Statistical Analysis Dataset			
Sample Parameter	2009	2010	2011
Sample Size	44	49	65
Sample Mean	2,258.4	2,335.7	2,467.8
Sample Standard Deviation	522.5	697.6	593.7

The report on that analysis was updated in August and September 2012 and is contained in Appendix G. Its results are paraphrased here for brevity. For the analysis, frequency response pertains to the absolute value of frequency response.

Key Statistical Findings

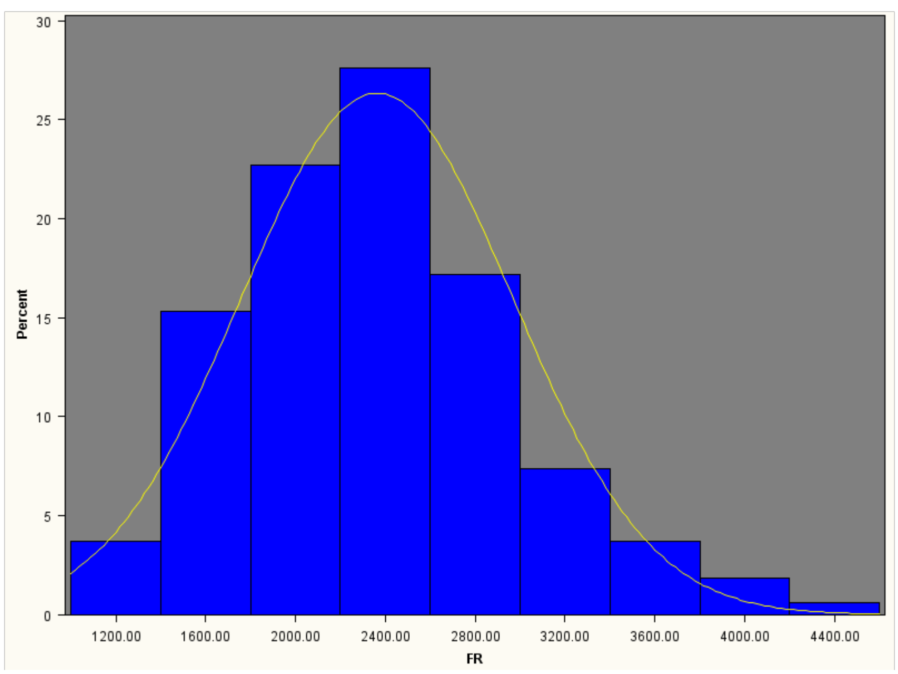
1. A linear regression equation with the parameters defined in Appendix G is an adequate statistical model to describe the relationship between time (predictor) and frequency response (responsive variable). The graph of the linear regression line and frequency response scatter plot is given in figure 14.

Figure 14: Linear Regression Fit Plot for Eastern Interconnection Frequency Response



2. The probability distribution of the whole frequency response dataset is approximately normal, with an expected frequency response of 2,363 MW/0.1 Hz and a standard deviation of 605.7 MW/0.1 Hz as shown in figure 15.

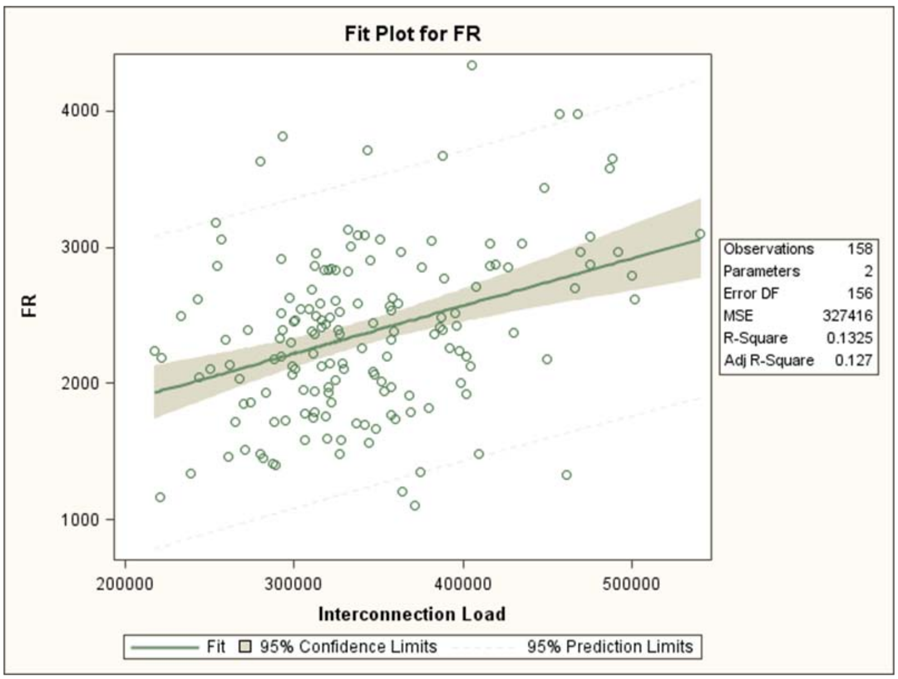
Figure 15: Probability Distribution Eastern Interconnection Frequency Response January 2009–April 2012



3. There is a statistically significant seasonal (summer/not summer) correlation to the variability of frequency response for the Eastern Interconnection. The expected frequency response (mean of the samples) for summer (June–August) frequency events is 2,598 MW/0.1 Hz versus 2,271 MW/0.1 Hz for non-summer events. This is attributable to at least two factors: higher load contribution to frequency response and increased generation dispatch of units with higher frequency response characteristics.

4. Pre-disturbance (average) frequency (Value A) is another statistically significant contributor to the variability of frequency response. The expected frequency response (mean of the samples) for events where Value A is greater than 60 Hz is 2,188 MW/0.1 Hz versus 2,513 MW/0.1 Hz for events where Value A is less than or equal to 60 Hz.

Figure 16: Linear Regression for Frequency Response and Interconnection Load



5. The difference in average frequency response between on-peak events and off-peak events is not statistically significant and could occur by chance. According to the NERC definition, Eastern Interconnection on-peak hours are designated as follows: Monday to Saturday from 07:00 to 22:00 hours (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Analysis showed that the on-peak/off-peak variable is not a statistically significant contributor to the variability of frequency response. There is a positive correlation of 0.06 between the indicator function of on-peak hours and frequency response; however, difference in average frequency response between on-peak events and off-peak events is not statistically significant and could occur by chance (P-value—the probability of obtaining a result at least as extreme—is 0.49).

6. There is a strong positive correlation of 0.364 between interconnection load and frequency response for the 2009–2011 events. On average, when interconnection load changes by 1,000 MW, frequency response changes by 3.5 MW/0.1 Hz.

   This correlation indicates a statistically significant linear relationship between interconnection load (predictor) and frequency response (response variable). Figure 16 shows the linear regression line and frequency response scatter plot. For the dataset, the regression line has a positive slope estimate of 0.00349; thus, the frequency response variable increases when interconnection load grows.

7. For the 2009–2011 dataset, five variables (time, summer, high pre-disturbance frequency, on-peak/off peak hour, and interconnection load) were involved in the statistical analysis of frequency response. Four of these—time, summer, on-peak hours, and interconnection load—have a positive correlation with frequency response (0.16, 0.24, 0.06, and 0.36, respectively), and the high pre-disturbance frequency has a negative correlation with frequency response (-0.26). The corresponding coefficients of determination R^2 (the square of correlation) indicate that about 2.6% in variability of frequency response can be explained by the changes in time, about 5.8% is seasonal, 0.4% is due to on-peak/off-peak changes, 13.3% is the effect of interconnection load variability, and about 6.9% can be accounted for by a high pre-disturbance frequency. However, the correlation between frequency response and on-peak hours is not statistically significant, with the probability of about 0.44 having occurred by mere chance (the same holds true for the corresponding R^2).

Table 2: Explanatory Variables for Eastern Interconnection Frequency Response

Variable X	Sample Correlation (X, FR)	P-Value	Linear Regression Statistically Significant	Coefficient of Determination R^2 (Single Regression)
Interconnection Load	0.36	<0.0001	Yes	13.3%
Value A > 60 Hz	-0.26	0.0008	Yes	6.9%
Summer/Not Summer	0.24	0.0023	Yes	5.8%
Date	0.16	0.044	Yes	2.6%
On-Peak Hours	0.06	0.438	No	N/A

Therefore, out of the five parameters, interconnection load has the biggest impact on frequency response followed by the indicator of high pre-disturbance frequency. A multivariate regression with interconnection load and starting frequency (Value A) greater than 60 Hz as the explanatory variables for frequency response yields a linear model with the best fit (it has the smallest mean square error among the linear models with any other set of explanatory variables selected from the five studied). Together these two factors can account for about 20% of the variability in frequency response.

Frequency response is, therefore, affected by other parameters that have low correlation with those studied and account for the remaining share of frequency response variability, minimizing the random error variance.

Note that interconnection load is positively correlated with summer (0.55), on-peak hours (0.45), and time (0.20), but is uncorrelated with starting frequency greater than 60 Hz (P-value of the test on zero correlation is 0.90).

Frequency Response Withdrawal

Withdrawal of primary frequency response is an undesirable characteristic associated most often with digital turbine-generator control systems using setpoint output targets for generator output. These are typically outer-loop control systems that defeat the primary frequency response of the governors after a short time to return the unit to operating at a requested MW output.

Figure 17: Primary Response Sustainability

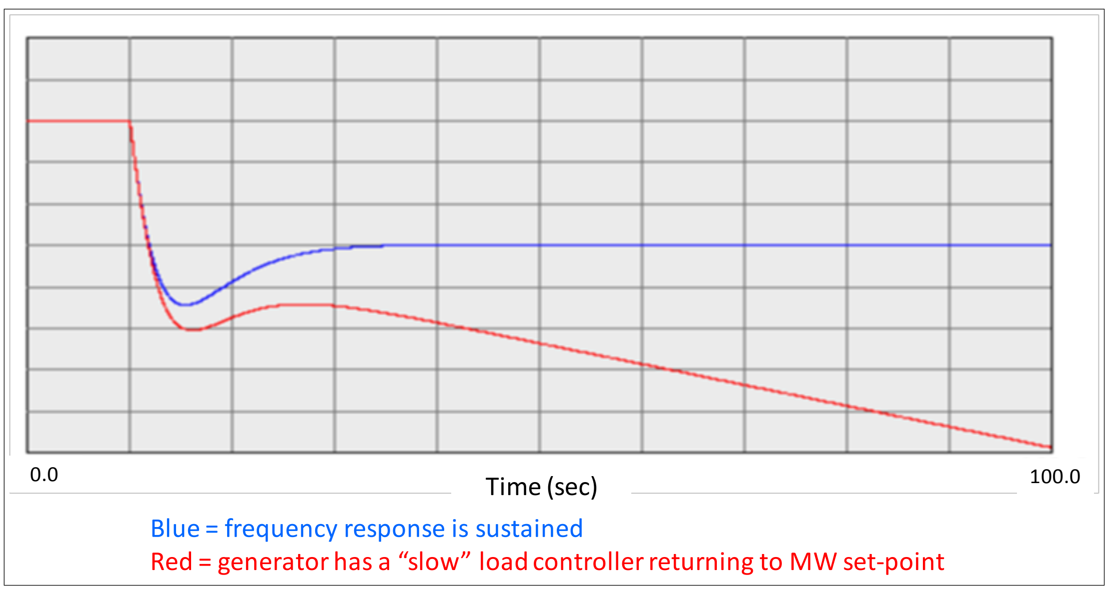


Figure 17 shows how the outer-loop control on a single machine would influence its ability to provide primary frequency response.

Some of the typical causes of the withdrawal are:

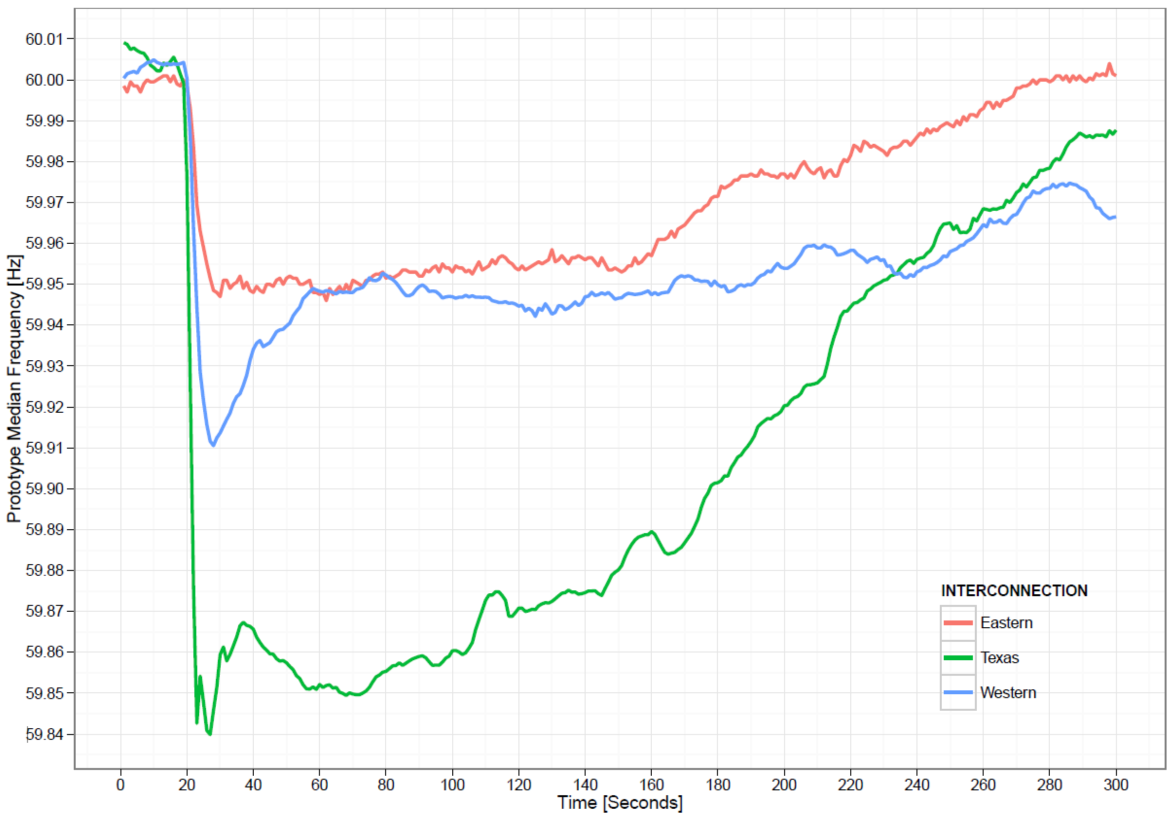
- Plant outer-loop control systems – driving the units to MW setpoints
- Unit characteristics

- Plant incapable of sustaining primary frequency response
- Governor controls overridden by other turbine/steam cycle controls

- Operating philosophies – operating characteristic choices made by plant operators
  - Desire to maintain highest efficiencies for the plant

The phenomenon is most prevalent in the Eastern Interconnection and can easily be seen in the comparison of the typical frequency response performance of the three interconnections (figure 18).

Figure 18: Typical Interconnection Responses for 2011[30]



Sustainability of primary frequency response becomes more important during light load conditions (nighttime) when there are generally fewer frequency-responsive generators on-line.

A number of the governor survey questions addressed the operational status and parameters of the governor fleet. The results of the survey show:

- About 90% of the generators were reported to have governors.

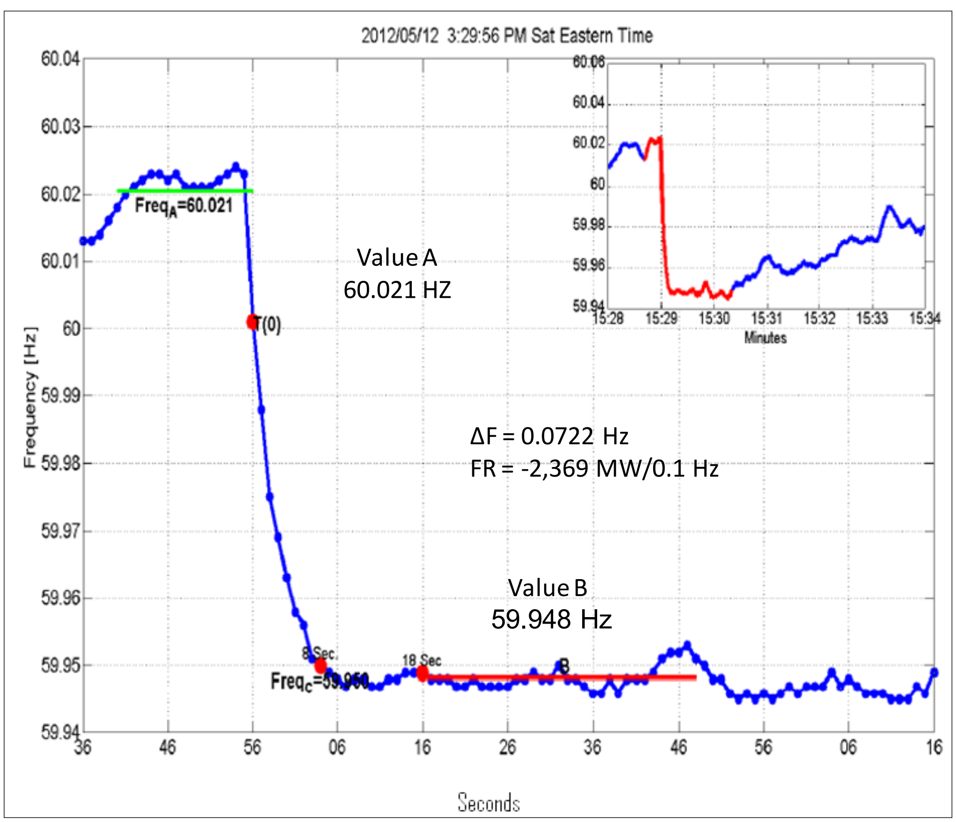
[30] NERC interconnections 2011 typical event frequency patterns using the median of the same second of each RS–FWG selected event – Revised: 09/26/12 provided by Advanced Systems Researchers.

- Virtually all (95–99% by interconnection) of the GOs and GOPs reported that their governors are operational.
- 80–85% (by interconnection) of the governors were reported to be capable of sustaining primary frequency response for longer than 1 minute if the frequency remained outside of their deadband.
- Roughly 50% of the governors reported that they had unit-level or plant-level control systems that override or limit governor performance.

Despite the fact that the majority of generators reported they have operational turbine governors, half of them have unit- or plant-level control systems that override governor responses. These control systems allow the units to return to scheduled output (MW setpoint) or an optimized operating point for economic reasons. These factors heavily influence the sustainability of primary frequency response, contributing to the withdrawal symptom often observed. This is often evident during light load periods in the middle of the night when high-efficiency, low-cost units that operate on MW setpoints are the majority of the generators dispatched to serve load.

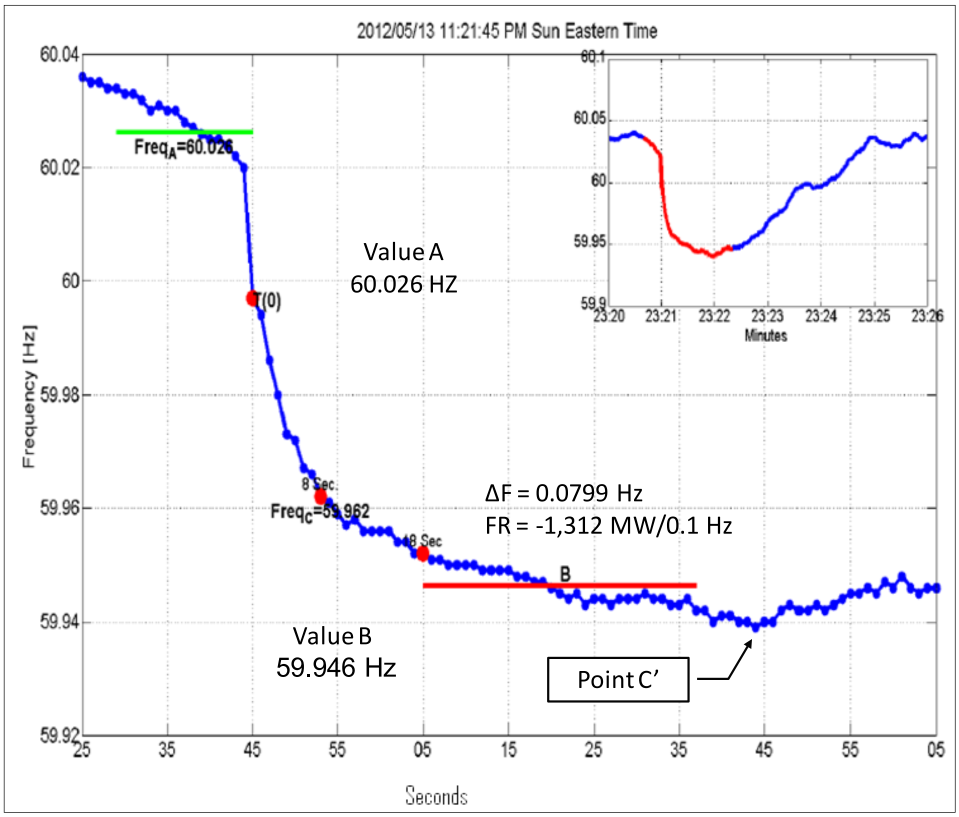
This was exhibited by two events involving generator trips in the spring of 2012 in one weekend. During the first event (figure 19), 1,711 MW of generation was tripped with a typical -2,369 MW/0.1 Hz frequency response.

Figure 19: 3:30 pm Saturday Afternoon 1,711 MW Resource Loss



The second event (figure 20) occurred late Sunday night when load in the Eastern Interconnection was much lighter, and the generators dispatched—probably the most efficient units—were of a different character. Despite the resource loss being almost 700 MW less, the frequency response of the interconnection was significantly reduced and exhibited the "lazy L" of primary frequency response withdrawal. Point C defined to occur during the first 8 seconds (at that time) was 59.962 Hz, while a lower point of about 59.939 Hz occurred about 1 minute after the event.

Figure 20: 11:21 pm Sunday Night 1,049 MW Resource Loss



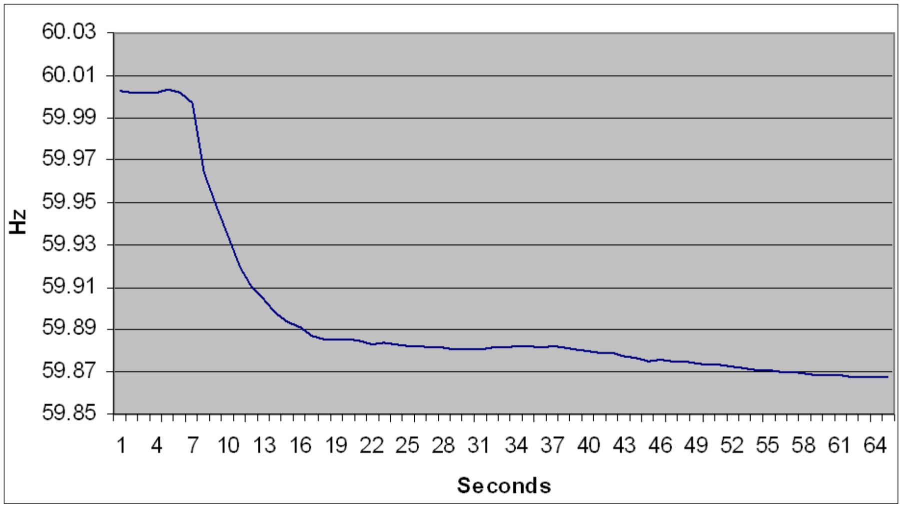
These two events point to the composition of the dispatch and the characteristics of the units on-line as primary elements in the frequency response strength, as well as the key elements in creating withdrawal. Therefore, when calculating an Interconnection Frequency Response Obligation (IFRO), it is important for operational planners and operators to recognize the potential for that withdrawal and the frequency consequentially being lower one to two minutes after the beginning of the event.

A similar withdrawal was experienced during the major frequency excursion of August 4, 2007 (figure 21). During that event some 4,500 MW of generation was lost.

The lowest frequency in the event was 59.868 Hz at about one minute after the start. Recovery to pre-event frequency was about 8 minutes, but the measurement of Value B (20 to 52 seconds) would not capture the lowest frequency. That frequency point is the true frequency event nadir, hereafter referred to as Point C' ("Point C Prime"), and is normally equal to Point C for events that don't exhibit the so-called "lazy L" effect.

It is important that the phenomenon be recorded and trended to determine if it is improving or deteriorating.

Figure 21: Interconnection Frequency – August 4, 2007 EI Frequency Excursion



Recommendation – Measure and track frequency response sustainability trends by observing frequency between T+45 seconds and T+180 seconds. A pair of indices for gauging sustainability should be calculated comparing that value to both Point C and Value B.

Modeling of Frequency Response in the Eastern Interconnection

Modeling of frequency response characteristics has been a known problem since at least 2008, when forensic modeling of the Eastern Interconnection required a "de-tuning" of the existing MMWG dynamics governor to 20% of modeled (80% error) to approach the measured frequency response values from the event.

Figure 22 shows the response comparison for that event analysis. Although the event was an over-frequency problem at that point, it is indicative of the larger problem of governor modeling in the Eastern Interconnection. The problem was further highlighted in the 2010 "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation," by Ernest Orlando Lawrence Berkeley National Laboratory (LBNL). In that analysis, an attempt was made to simulate a 4,500 MW loss event that occurred on August 4, 2007. Figure 23 shows a comparison of the simulation to the measured frequency from the event.

Figure 22: 2007 Event Frequency Response Forensic Analysis

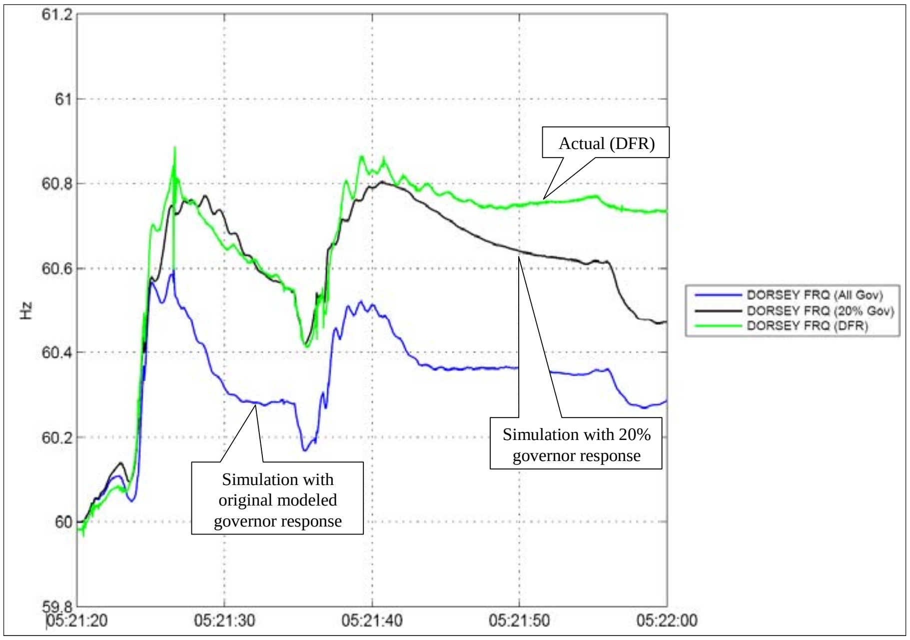
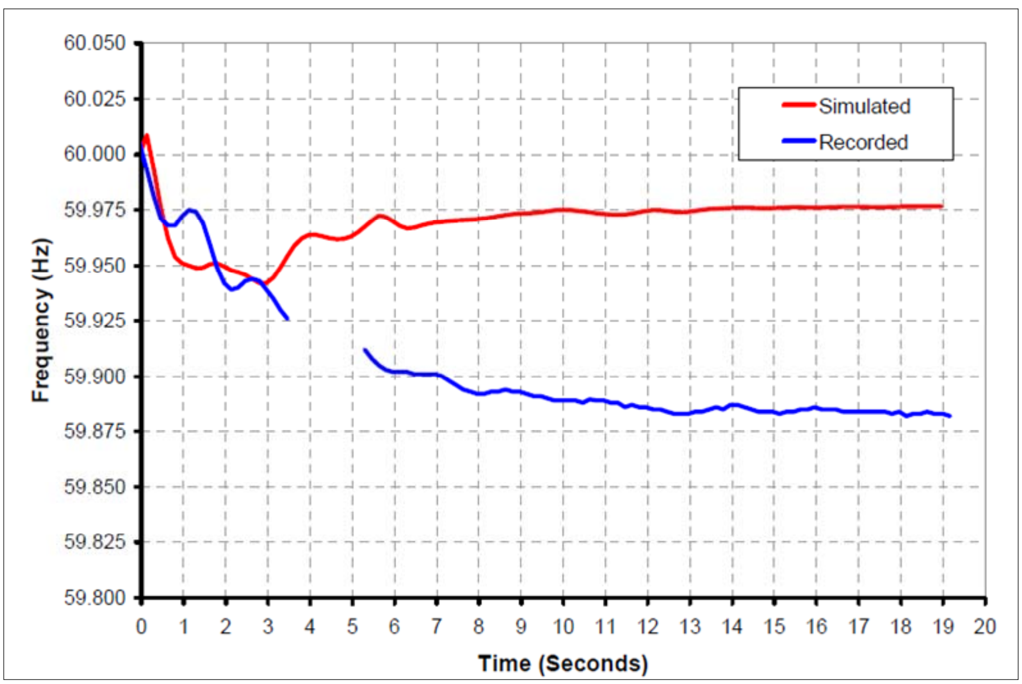


Figure 23: Eastern Interconnection Frequency Response – August 4, 2007 Initial 20 Seconds



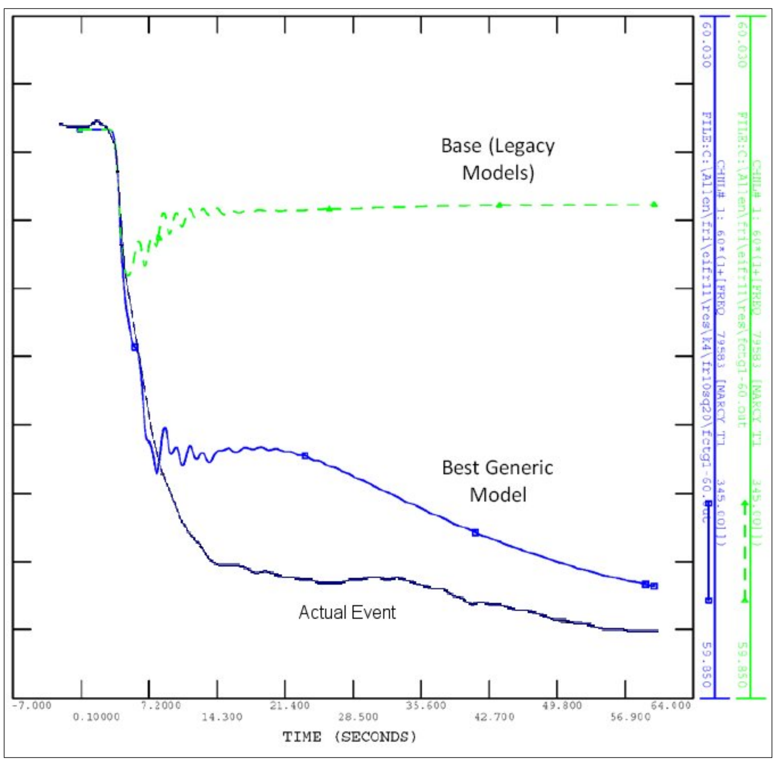
As part of the NERC Frequency Response Initiative and the Modeling Improvements Initiative, NERC collaborated with the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) to perform an analysis of the modeling of overall frequency response in the Eastern Interconnection. That review was a prelude to a plan for thorough examination of the governor models in the Eastern Interconnection dynamics study cases that are assembled by the MMWG. That report stated, “The turbine-governor modeling currently reflected in the MMWG dynamics simulation database is not a valid representation of the frequency control behavior of the Eastern Interconnection.”

That project created a “generic case” dynamics model, replacing the turbine governor models in the case with a generic governor model in order to ascertain the basic characteristics of the frequency response of the Eastern Interconnection. Figure 24 shows a comparison of the actual event data and the simulations using the original governor data and the generic case.

The characteristics found in that study were:

- Only 30% of the units on-line provide primary frequency response.
- Two-thirds of the units that did respond exhibit withdrawal of primary frequency response.
- Only 10% of units on-line sustain primary frequency response.

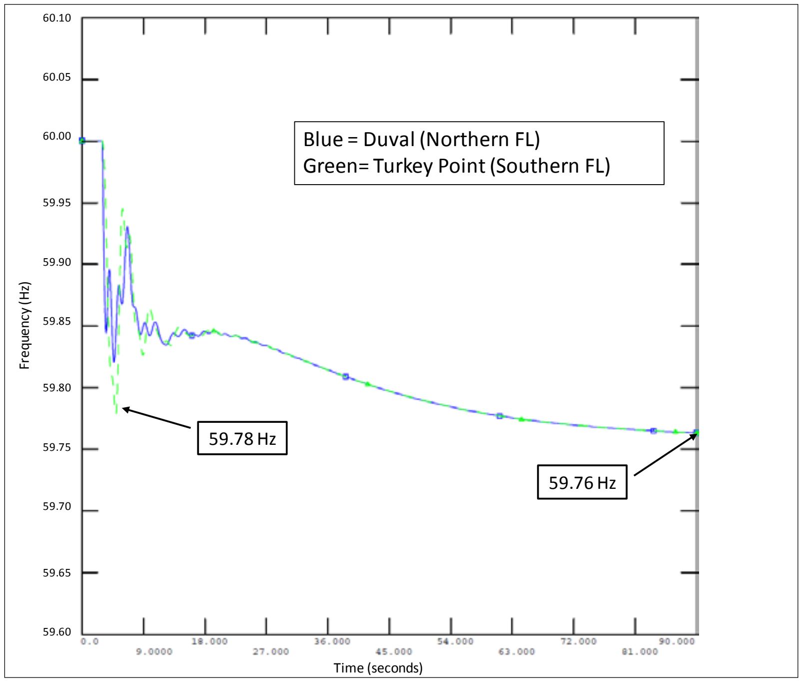
Figure 24: Comparison of Legacy and Generic Simulations to August 4 Event



Following that study, a follow-on analysis was performed by NERC staff to determine the general order of magnitude of a frequency event that could be sustained by the Eastern Interconnection without violating the 59.7 Hz first step UFLS in FRCC. A simulation was run that tripped about 8,500 MW of generation in the southeast United States (north of Florida). Figure 25 shows the result of that testing.

The simulation showed that the lowest frequency would be about 59.76 Hz in southern Florida. The initial nadir of 59.78 Hz in southern Florida is lower than the nadir in northern Florida due to the wave properties of the disturbance.

Figure 25: 8,500 MW Resource Loss Simulation



Although the simulations using the generic governor models are not exact, that analysis is indicative of the Eastern Interconnection's ability to sustain a resource loss event significantly higher than the Resource Contingency Protection Criteria proposed in this report.

Concerns for Future of Frequency Response

There is a growing concern about the future of frequency response in light of a number of factors:

- **Electronically coupled resources** – The incorporation of renewable resources such as wind and solar and the increasing penetration of variable speed motor drives presents a continuing erosion of system inertia; all are electronically coupled to the system. As such, those resources, unless specifically designed to mimic inertial response, do not have inertial response.

- **Electronically coupled loads** – As synchronous motors are replaced by variable speed drives, the load response of the motors is eliminated by the power electronics of the motor controller. This reduces the load damping factor for the interconnection.

- **Displacement of traditional turbine-generators in the dispatch** – Traditional turbine-generators are being displaced in the dispatch, particularly during off-peak hours when wind generation is at its highest and the loads and generation levels are at their lowest.

Such displacement of frequency responsive resources increasingly depletes the inertia of the interconnection at those times.

Role of Inertia in Frequency Response

Inertia plays a crucial role in determining the slope of a frequency decline during a resource loss event.

The slope of frequency excursion is determined by the inertia of the system and a factor to account for the load damping characteristics of the interconnection.

$$Slope = \frac{\Delta Power}{D + 2H}$$

Where:

D = Load Damping Factor

The load damping factor ranges from 0 to 2, where 2 would represent a load of all motors.

H = Inertia Constant of the interconnection

The inertia constant ranges from 2.5 to 6.5

Figure 26 shows the sensitivity of frequency response to changes to system inertia. The lower green curve represents an inertia constant of 2.5, and the lower red curve represents an inertia constant of 5.0.

Figure 26: Frequency Response Sensitivity to System Inertia

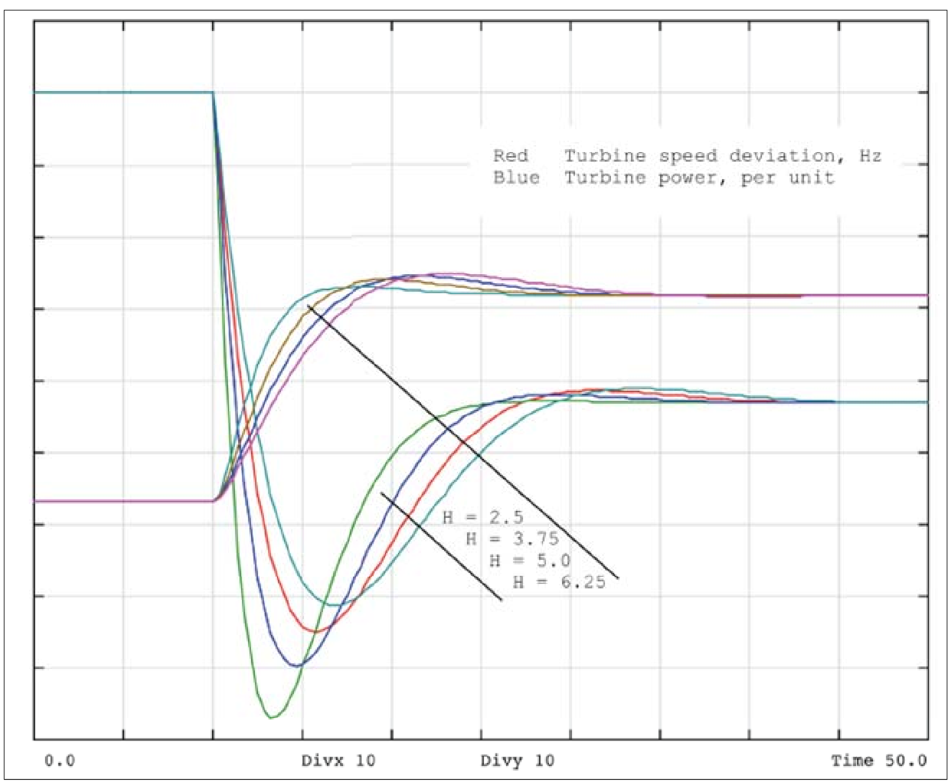
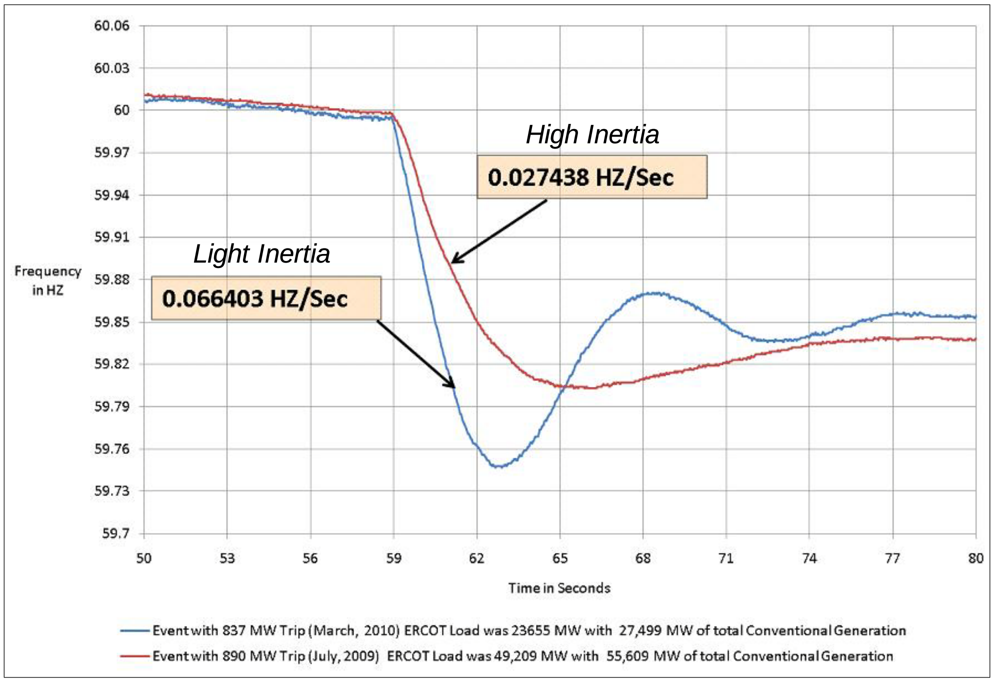


Figure 27 shows an actual example from ERCOT of how frequency response is changed for similarly sized resource loses with differences in inertia. It is clear that when the inertia on the system is lower, a similar resource MW loss creates a much steeper and deeper frequency excursion. This is a good example of the displacement of traditional resources with electronically coupled resources during light load periods.

Figure 27: Inertial Response Sensitivity



Need for Higher Speed Primary Frequency Response

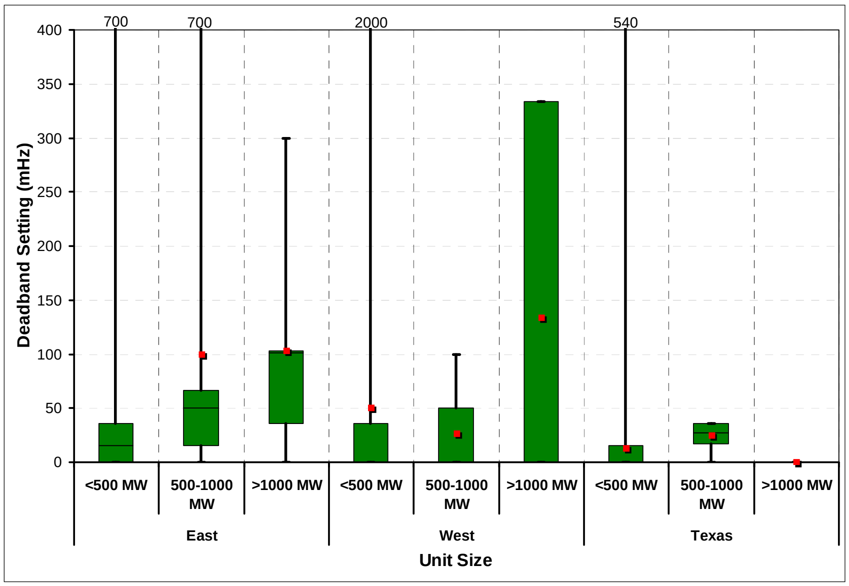
The reduction of inertia drives a need for higher speed response to frequency excursions. If the slope of the frequency decline is steeper, it is necessary for high-speed injection of energy to arrest the decline in order to prevent the excursion from being too deep. Such energy injection can come from a number of sources, such as energy storage devices and wind turbines with modified inverters.

Preservation or Improvement of Existing Generation Primary Frequency Response

Additionally, to further ensure strong overall frequency response, it is important to preserve or improve the primary frequency response of the existing generation fleet. The Role of Governors section of this report discusses the results of the 2010 survey on generator governors. The survey results show that there is a significant portion of the existing generator fleet that has operational governors. However, the reported deadband ranges make those governors ineffective for all but catastrophic losses of resources. Figure 28 shows the reported deadband ranges.

If the existing generator fleet primary frequency response performance can be improved through adjustments in deadbands and implementation of no-step droop responses, a significant improvement in interconnection frequency response could be realized. Further, if all of the existing generators were made capable of response, any generators that are on-line during light load periods would be more able to provide response.

Figure 28: Reported Governor Deadband Settings



The Role of Governors section of this report recommends immediate development of a NERC turbine-generator governor guideline calling for deadbands of ±16.67 mHz with droop settings of 4%–5% depending on turbine type in order to retain or regain frequency response capabilities of the existing generator fleet.

Withdrawal of Primary Frequency Response

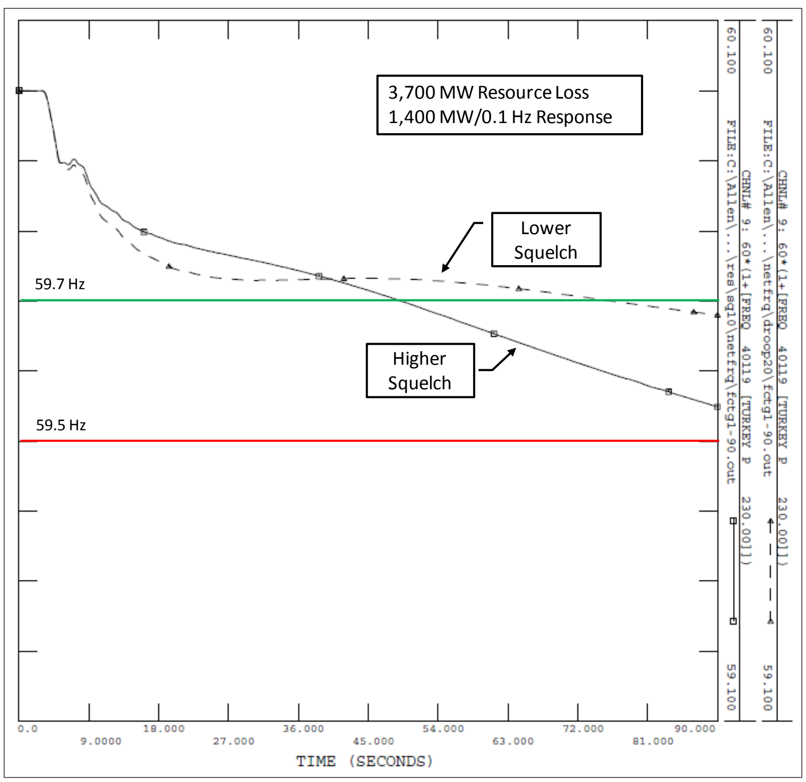
Withdrawal of primary frequency response caused by outer-loop control systems must be addressed. As shown in the Frequency Response Withdrawal section of this report, frequency response during light load periods can be highly influenced by the mix of dispatched resources. Economics of the dispatch dictates that the most efficient, cost-effective generation will remain on-line during those periods. Such generation employs setpoint controls that return generation to AGC-prescribed or efficiency-prescribed generation levels regardless of system frequency. This results in "squelching" of any primary frequency response that the governors may have provided during a frequency event. This withdrawal of primary response before secondary frequency response from AGC becomes effective starting at about T+45 to T+60 seconds, creating the "lazy L" event response prevalent in the Eastern Interconnection.

To illustrate this effect, a dynamic simulation of a 3,700 MW resource loss frequency event was performed for the Eastern Interconnection using the generic dynamics case described in the Modeling of Frequency Response in the Eastern Interconnection section of this report. Two simulation runs were performed to mimic about 1,400 MW/0.1 Hz frequency response (between 20 and 52 seconds), with different combinations of generator dispatch and differing amounts of response "squelch." Figure 29 shows that the effects on frequency response sustainability can be highly influenced by the composition of the resource dispatch, even with the same measured frequency response.

There are potential ways of alleviating this withdrawal symptom, including introduction of a frequency bias into the outer-loop controls systems that would prevent withdrawal of primary frequency response, similar to the frequency bias settings in an automatic generation control (AGC) system.

Recommendation – NERC should include guidance on methods to reduce or eliminate the effects of primary frequency response withdrawal by outer-loop unit or plant control systems.

Figure 29: Simulations of Varying Levels of Primary Frequency Response Withdrawal Eastern Interconnection



Note that these simulation runs were done for illustrative purposes only; the simulations are not yet accurate enough to confidently predict system performance, and AGC secondary frequency response was NOT simulated. Secondary frequency response from AGC becomes effective starting at about T+45 to T+60 seconds.

Interconnection Frequency Response Obligation (IFRO)

Tenets of IFRO

The IFRO is intended to be the minimum amount of frequency response that must be maintained by an interconnection. Each Balancing Authority in the interconnection should be allocated a portion of the IFRO that represents its minimum responsibility. In order to be sustainable, Balancing Authorities that may be susceptible to islanding may need to carry additional frequency responsive reserves to coordinate with their under-frequency load shedding (UFLS) plans for islanded operation.

A number of methods to assign the frequency response targets for each interconnection can be considered. Initially, the following tenets should be applied:

1. A frequency event should not trip the first stage of regionally approved UFLS systems within the interconnection.
2. Local tripping of first-stage UFLS systems for severe frequency excursions, particularly those associated with protracted faults or on systems on the edge of an interconnection, may be unavoidable.
3. Other frequency-sensitive loads or electronically coupled resources may trip during such frequency events (as is the case for photovoltaic inverters in the Western Interconnection).
4. Other susceptible frequency sensitivities may have to be considered in the future (e.g., electronically coupled load common-mode sensitivities).

UFLS is intended to be a safety net to prevent against system collapse from severe contingencies. Conceptually, that safety net should not be violated for frequency events that happen on a relatively regular basis. As such, the resource criteria are selected to avoid violating UFLS settings approved by the Regional Entities.

The Frequency Responsive Reserve Standard Drafting Team (FRRSDT) is proposing an administered value approach for the BAL-003-1 field trial. Eventually, an agreed-upon method of determining the interconnection FRO will be included in a reliability standard, or in the NERC Rules of Procedure.[31]

[31] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

Statistical Analyses

Frequency Variation Statistical Analysis

A statistical analysis of the variability of frequency for each of the four interconnections was performed using 1-second measured frequency for the Eastern, Western, and ERCOT Interconnections for 2007–2011 (five years). Data for the Québec Interconnection was only available for 2010 and 2011. Analysis of data showed the Western Interconnection frequency deviations (Epsilon) to be more volatile since the Balancing Authority ACE Limit (BAAL) field trial began there in March of 2010. Therefore, it was decided to limit the analysis to the years 2009–2011 to more accurately portray the current frequency characteristics.

This variability accounts for items such as time error correction; variability of load, interchange, and frequency over the course of a normal day; and other uncertainties, including time error corrections and all frequency events—no large events were excluded. The results of the analysis are shown in table 3.

Table 3: Interconnection Frequency Variation Analysis (Hz)

Value	Eastern	Western	ERCOT	Québec
Timeframe	2009–2011	2009–2011	2009–2011	2010–2011
Number[32] of Samples	91,283,555	90,446,802	85,924,929	34,494,049
Expected Value	60.0000367	59.9999522	59.9999847	60.00002303
Maximum Value	60.3090	60.3575	62.1669	60.8776
Minimum Value	59.0015	59.7364	58.0000	59.1879
Variance of Frequency (σ^2)	0.00024092 Hz^2	0.00022266 Hz^2	0.00060749 Hz^2	0.00035315 Hz^2
σ	0.01552147	0.01492184	0.02464722	0.01879236
2σ	0.03104295	0.02984369	0.04929445	0.03758472
3σ	0.04656442	0.04476553	0.07394167	0.05637708
Starting Frequency (F_{Start}) 5% of lower tail samples	59.974	59.976	59.963	59.972

[32] Numbers of samples vary due to exclusion of data drop-outs and other obvious observation anomalies.

For each interconnection, the distribution of the interconnection frequency fails the normality test (both the chi-square goodness-of-fit and the Kolmogorov-Smirnov goodness-of-fit) at any standard significance level. The combined datasets for the interconnection frequency consist of very large numbers of observations. For such large samples, the empirical distribution can be considered as a very good approximation of the actual distribution of the frequency, and was judged a better predictor than use of standards deviation for predicting the interconnection starting frequencies for an event. The rate of convergence in the Glivenko-Cantelli theorem is $n^{(-1/2)}$, where n is the sample size. Therefore, quantiles of the empirical distribution function can be used directly to calculate intervals where values of frequency belong with any pre-determined probability.

Only resource losses (frequency drops) are examined for IFRO calculations, so the focus is on the one-sided lower tail of the distribution for frequencies that fall outside the upper 95% interval of the overall distribution. Therefore, the starting frequency that should be used for the calculation of the IFROs is the 10% quantile frequency value, which represents a 95% confidence in the prediction for that single tail.

Those starting frequencies encompass all variations in frequency, including changes to the target frequency during time error correction. That eliminates the need to expressly evaluate TEC as a variable in the IFRO calculation.

Recommendation – The starting frequency for the calculation of IFROs should be frequency of the 5% of lower tail of samples from the statistical analysis, representing a 95% confidence that frequencies will be at or above that value at the start of any frequency event.

Figures 30–33 show the interconnection histograms broken into 1-mHz "bins." A complete set of graphs for the four interconnections is located in Appendix D of this report.

Figure 30: Eastern Interconnection 2009–2011 Frequency Histogram

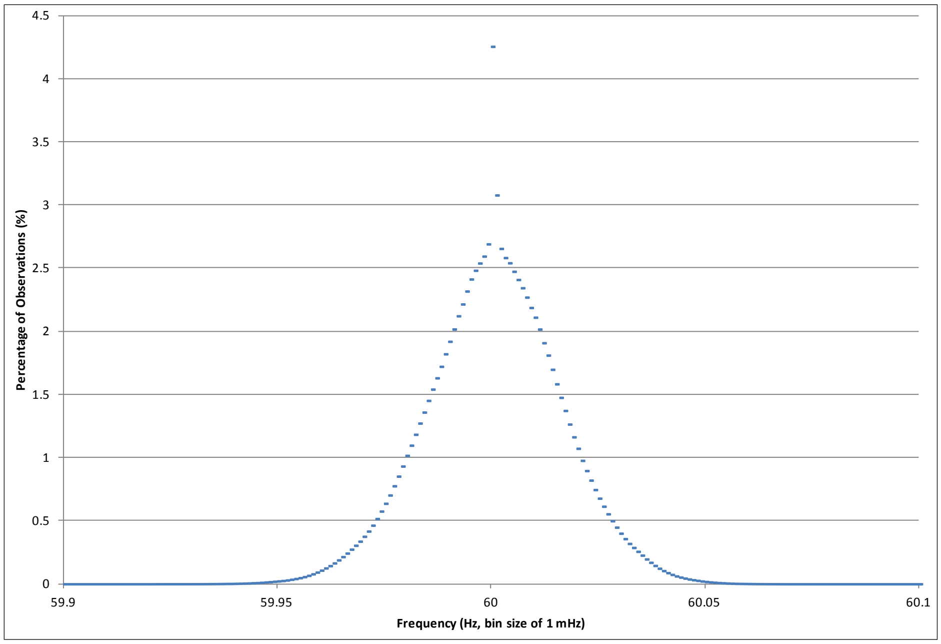


Figure 31: Western Interconnection 2009–2011 Frequency Histogram

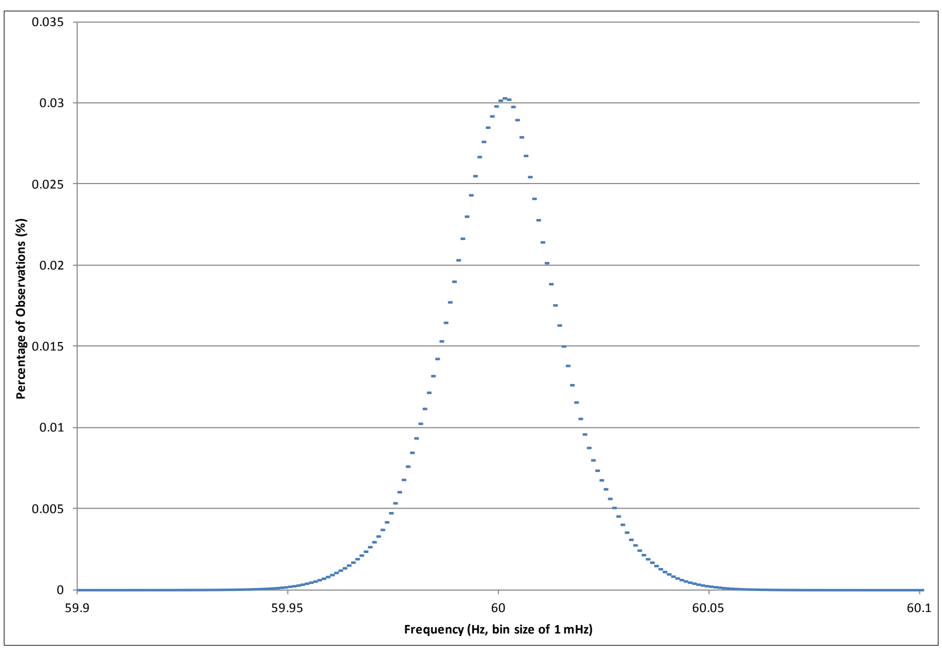
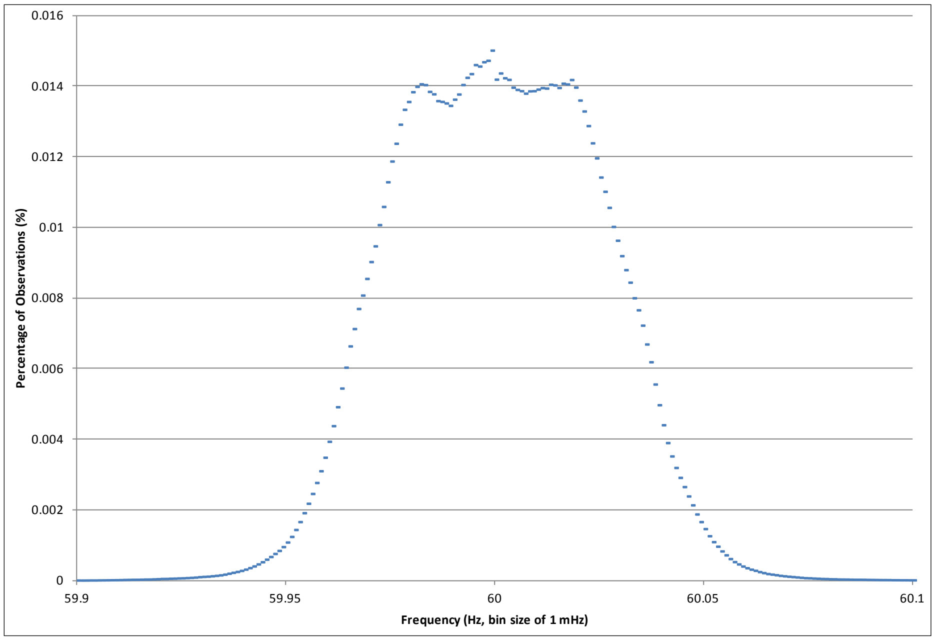
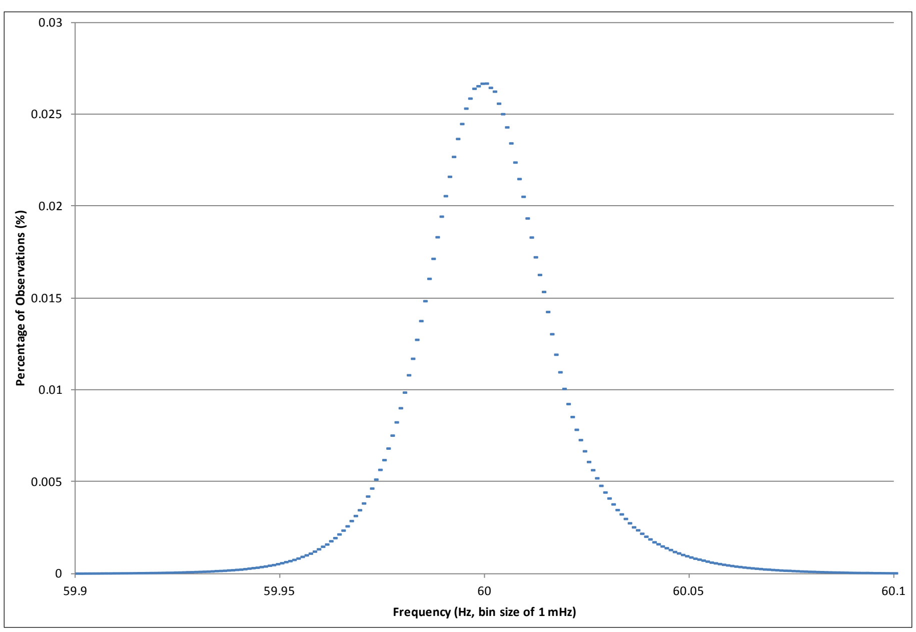


Figure 32: ERCOT Interconnection 2009–2011 Frequency Histogram



Note that the ERCOT frequency histogram displays the influence of the "flat-top" f profile that was common to that interconnection prior to 2008. That phenomenon was caused by a standardized ±36 mHz deadband with a step-function implementation. Additional discussion on that topic is in the ERCOT Experience section of this report.

Figure 33: Québec Interconnection 2010–2011 Frequency Histogram



Point C Analysis – One-second versus Sub-second Data

Additional statistical analysis was performed for the differences between Point C and Value B calculated as a ratio of Point C to Value B using 1-second data for events from December 2010 through May 2012. Although the 1-second data sample is robust, it does not necessarily ensure the nadir of the event was accurately captured. To do so requires sub-second measurements that can only be provided by PMUs or FDRs. Therefore, a "CC" adjustment component (CC_{ADJ}) for the IFRO calculation was designed to account for the differences observed between the 1-second Point C and high-speed Point C measurements.

Table 4: Analysis of One-second and Sub-second Data for Point C (CC_{ADJ})

Interconnection	Number of Samples	Mean	Standard Deviation	CC_{ADJ} (95% Quantile)
Eastern	30	0.0006	0.0038	0.0068
Western	17	0.0012	0.0019	0.0044
ERCOT	58	0.0021	0.0061	0.0121
Québec[33]	0	N/A	N/A	N/A

This adjustment should be made to the allowable frequency deviation value before it is adjusted for the ratio of Point C to Value B. Note: No sub-second data was available for the Québec Interconnection.

Recommendation – The allowable frequency deviation (starting frequency minus the highest UFLS step) should be reduced by the CC_{ADJ} to account for differences between the 1-second and sub-second data for Point C as listed in table B-C9.

Adjustment for Differences between Value B and Point C

All of the calculations of the IFRO are based on protecting from instantaneous or time-delayed tripping of the highest step of UFLS, either for the initial nadir (Point C), or for any lower frequency that might occur during the frequency event. The frequency variance analysis in the previous section of this report is based on 1-second data from 2007 through 2011 (except Québec 2010 and 2011 only).

As a practical matter, the ability to measure the tie line and loads for the Balancing Authorities is limited to system control and data acquisition (SCADA) scan-rate data of 1–6 seconds. Therefore, the ability to measure frequency response of the Balancing Authorities is still limited by the SCADA scan rates available to calculate Point B.

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[33] Sub-second data from Québec was not available.

Candidate events from the ALR1-12 Interconnection Frequency Response selection process (Appendix E) for frequency response analysis were used to analyze the relationship between Value B and Point C for the significant frequency disturbances from December 2010 through May 2012. This sample set was selected because data was available for the analysis on a consistent basis. This resulted in the number of events shown in table 5.

Analysis Method

When evaluating some physical systems, the nature of the system and the data resulting from measurements derived from that system do not fit the standard linear regression methods that allow for both a slope and an intercept for the regression line. In those cases, it is better to use a linear regression technique that represents the system correctly.

The Interconnection Frequency Response Obligation is a minimum performance level that must be met by the Balancing Authorities in an interconnection. Such response is expected to come from the frequency response in MWs of the Balancing Authorities to a change in frequency. As such, if there is no change in frequency there should be no change in MWs resulting from frequency response.

This response is also related to the function of the frequency bias setting in the ACE equation of the Balancing Authorities for longer term. The ACE equation looks at the difference between scheduled frequency and actual frequency times the frequency bias setting to estimate the amount of MWs that are being provided by load and generation within the Balancing Authority. If the actual frequency is equal to the scheduled frequency, the frequency bias component of ACE must be zero.

Since the IFRO is ultimately a projection of how the interconnection is expected to respond to changes in frequency related to a change in MW (resource loss or load loss), there should be no expectation of frequency response without an attendant change in MW. It is this relationship that indicates the appropriateness of the use of regression with a forced fit through zero.

Evaluation of data to determine C-to-B ratio:

The evaluation of data to determine C-to-B ratio to account for the differences between arrested frequency response (to the nadir, Point C) and settled frequency response (Value B) is also based on a physical representation of the electrical system. Evaluation of this system requires investigation of the meaning of an intercept. The C-to-B ratio is defined as the difference between the pre-disturbance frequency and the frequency at the maximum deviation in post-disturbance frequency, divided by the difference between the pre-disturbance frequency and the settled post-disturbance frequency.

$$CB_R = \frac{Value\ A - Point\ C}{Value\ A - Value\ B}$$

A stable physical system requires the ratio to be positive; a negative ratio indicates frequency instability or recovery of frequency greater than the initial deviation.

Table 5: Analysis of Value B and Point C (CBR)				
Interconnection	Number of Samples	Mean	Standard Deviation	CB_R (95% Quantile)
Eastern	41	0.964	0.0149	1.0 (0.989)[34]
Western	30	1.570	0.0326	1.625
ERCOT	88	1.322	0.0333	1.377
Québec[35]				1.550

This statistical analysis was completed using 1-second averaged data that does not accurately capture Point C and is better measured by high-speed metering (PMUs or FDRs). Therefore, a separate correction must be used to account for the differences between the Point C in the 1-second data and the Point C values measured with sub-second measurements from the FNet FDRs.

The CB_R value for the Eastern Interconnection indicates that the Value B is generally below the Point C value. Therefore, there is no adjustment necessary for that interconnection.

The Québec Interconnection's resources are predominantly hydraulic and are operated to optimize efficiency, typically at about 85% of rated output. Consequently, most generators have about 15% headroom to supply primary frequency response. This results in a robust response to most frequency events, exhibited by high rebound rates between Point C and the calculated B Value. For the 26 frequency events in their event sample, Québec's CB_R value would be 3.613, or two to three times as high as the CB_R value of other interconnections. Using the same calculation method for CB_R would effectively penalize Québec for their outstanding rebound performance and make their IFRO artificially high. Therefore, the method for calculating the Québec CB_R was modified.

Québec operates with an operating mandate for frequency responsive reserves to protect from tripping their 58.5 Hz (300 ms trip time) first step UFLS for their largest hazard at all times, effectively protecting against tripping for Point C frequency excursions. They also protect against tripping a UFLS step set at 59.0 Hz that has a 20-second time delay, which protects them for Value B low frequency and any withdrawals. This results in a Point C to Value B ratio of 1.5. To account for the confidence interval, 0.05 is then added, making the CB_R = 1.550.

Adjustment for Primary Frequency Response Withdrawal

At times, the nadir for a frequency event occurs after Point C—defined in BAL-003-1 as occurring in the T+0 to T+12 second period, during the Value B averaging period (T+20 through T+52 seconds), or later. For purposes of this report, that later occurring nadir is termed Point

[34] CB_R value limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[35] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 millisecond operating time (responsive to Point C)and 59.0 Hz UFLS step with a 20 second delay (responsive to Value B or beyond).

C'. This lower nadir is symptomatic of primary frequency response withdrawal, or squelching, by unit or plant-level outer-loop control systems. Withdrawal is most prevalent in the Eastern Interconnection, as described earlier.

As described in the Withdrawal of Primary Frequency Response section of this report, frequency response withdrawal can become important depending on the type and characteristics of the generators in the resource dispatch, especially during light load periods. Therefore, an additional adjustment to the maximum allowable delta frequency for calculating the IFROs was statistically developed. This adjustment should be used whenever withdrawal is a prevalent feature of frequency events. Initially, it is only being applied to the Eastern Interconnection.

Table 6 shows the statistical results of the analysis based on the 34 frequency response events in the Eastern Interconnection. Note that the expected timeframe for the C' nadir to occur is about 82 seconds after the start of the event.

Table 6: Statistical Analysis of the Adjustment for C' Nadir (BC'_{ADJ})

Value	Number of Samples	Mean	Standard Deviation	BC'_{ADJ} (95% Quantile)
Delta Frequency from Value B to Point C' Nadir	34	4.0 mHz	8.2 mHz	17.5 mHz
Seconds from T+0 to C' Nadir	34	38.9 s	26.3 s	82.1 s

This BC'_{ADJ} should be applied to the allowable delta frequency after the differences from Value B to Point C are adjusted. The values driving this adjustment should also be carefully monitored and the adjustment recalculated during the annual review of IFRO calculations.

Variables in Determination of Interconnection Frequency Response Obligation from Criteria

To make a determination of the appropriate Resource Contingency Protection Criteria to protect for a certain kind of event, the MW target value needs to be translated into an Interconnection Frequency Response Obligation (IFRO) for an appropriate comparison. A number of other variables must be taken into consideration.

Low Frequency Limit

The low frequency limit to be used for the IFRO calculations should be the highest setpoint in the interconnection for regionally approved UFLS systems.

Recommendation – Based on the tenet that UFLS should not trip for a frequency event throughout the interconnection, the recommended UFLS first-step limitations for IFRO calculations listed in table 7 should be used.

Table 7: Low-Frequency Limits (Hz)	
Interconnection	Highest UFLS Trip Frequency
Eastern	59.5[36]
Western	59.5
ERCOT	59.3
Québec	58.5

The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, while the prevalent highest setpoint in the rest of that interconnection is 59.5 Hz. The FRCC 59.7 Hz first UFLS step is based on internal stability concerns and preventing the Florida peninsula from separation from the rest of the interconnection. The FRCC concluded that the IFRO starting point of 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation for an interconnection resource loss event than for an internal FRCC event.

Protection against tripping the highest step of UFLS does not ensure that generation that has frequency-sensitive protection or turbine control systems will not trip. Severe system conditions might drive the frequency to levels that may present protection and control systems with a combination of conditions that may cause the generation to trip, such as severe rate of change in voltage or frequency, which might actuate volts per hertz relays. Similarly, some combustion turbines may not be able to sustain operation at frequencies below 59.5 Hz. Recent laboratory testing by Southern California Edison of inverters used on residential and commercial scale photovoltaic (PV) systems revealed a propensity to trip at about 59.4 Hz, which is 200 mHz above the expected 59.2 Hz prescribed in IEEE Standard 1547 for distribution-connected PV rating ≤ 30 kW (57.0 Hz for larger installations). This could become problematic in areas of high penetration of photovoltaic resources.

Credit for Load Resources (CLR)

The ERCOT Interconnection depends on contractually interruptible demand that automatically trips at 59.7 Hz to help arrest frequency declines. A 1,400 MW Load Resource (formerly Load acting as a Resource – LaaR) credit is included against the Resource Contingency for the ERCOT Interconnection. Similarly, there is a remedial action scheme (RAS) in WECC that trips 300 MW of load for the loss of two Palo Verde generating units.

For the Western Interconnection, if the larger 3,200 MW resource loss activates the RAS and trips the Pacific DC Intertie (PDCI), the 300 MW credit for Load Resources associated with the loss of the two Palo Verde units does not apply.

[36] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

For both interconnections, credit for load resources is handled in the calculation of the IFRO as a reduction to the loss of resources, when appropriate.

Interconnection Resource Contingency Protection Criteria

Selection of discrete event protection criteria for each interconnection must be done before the IFRO can be calculated. The protection criteria selected should ensure that Point C would not encroach on the first step UFLS. However, the criteria may need to be different from one interconnection to the other due to the differences in size and design characteristics.

The following potential interconnection event criteria were considered:

- largest N-2 loss-of-resource event,
- largest total generating plant with common voltage switchyard, and
- largest loss-of-resource event in the interconnection in the last 10 years.

Largest N-2 Event

For this approach, each interconnection will have a target Resource Contingency Protection Criteria based on the largest N-2 loss-of-resource event. This should not be confused with a Category C, N-2 event prescribed in the NERC TPL standards; it is intended to reflect a simultaneous loss of the resources without time for system adjustments. As such, these events would be considered Category D events in the current standards.

Table 8: Largest N-2 Event

Interconnection	Basis	MW
Eastern	Nelson DC Bi-poles 1 & 2	3,854[37]
Western	Two Palo Verde Units	2,740[38]
ERCOT	Two South Texas Project Units	2,750[39]

For both the ERCOT and Western Interconnections, that would be the loss of the two largest generating units in the interconnection. However, for the Eastern Interconnection, the largest N-2 loss-of-resource event would be the loss of the two Nelson dc bi-pole converters.

[37] Nelson Bi-poles 1 and 2 are rated 1,854 MW and 2,000 MW, respectively.

[38] Net winter ratings per Form EIA-860 reporting.

[39] Net rating from ERCOT Resource Asset Registration Form (RARF).

Largest Total Plant with Common Voltage Switchyard

Another approach is to examine the largest complete generating plant outage in each of the interconnections, limiting this classification to those generators with a common voltage switchyard. The reasoning for considering such a protection criteria is that despite popular belief, complete plant outages can and do happen on a regular basis; 15 complete plant outages occurred in North America in the 12 months from July 1, 2010 through June 30, 2011.

Table 9: Largest Total Plant with Common Voltage Switchyard		
Interconnection	Basis	MW
Eastern	Darlington Units 1-4	3,524[40]
Western	3 Palo Verde Units	3,575[41]
ERCOT	2 South Texas Project Units	2,750[42]

Note that in the Western Interconnection, multi-plant generation tripping by the operation of the Pacific Northwest remedial action scheme (RAS) results in resource loss of 3,200 MW. That issue is further discussed in the Special IFRO Considerations section of this report.

Largest Resource Event in Last 10 Years

A third approach is to examine the largest complete resource loss event in the interconnection over the last 10 years. Although this method yields a reasonable value for the Eastern Interconnection, the values for the other two interconnections would likely not be sustainable without activating some UFLS. It also results in a larger resource contingency for the Western Interconnection than for the Eastern Interconnection. These single events were not approached in magnitude by any other events in the 10-year period.

Table 10: Largest Resource Contingency Event in Last 10 Years		
Interconnection	Basis	MW
Eastern	August 4, 2007 Disturbance[43]	4,500
Western	June 14, 2004 Disturbance[44]	5,000
ERCOT	May 15, 2003 Disturbance[45]	3,400

[40] Net winter ratings from the NERC Electricity Supply and Demand.

[41] Net winter ratings per Form EIA-860 reporting.

[42] Net rating from ERCOT Resource Asset Registration Form (RARF).

[43] The August 4, 2007 frequency excursion was a complex, multi-faceted event involving nine generators across three states. Of those nine generators, seven tripped because of turbine control actions, and the others tripped on instability. This was not an N-1 event.

[44] The June 14, 2004 disturbance was a complex series of events thattripped ten generators across the western Interconnection as the result of a protracted fault. This was not an N-1 event.

Recommended Resource Contingency Protection Criteria

Because the philosophy is for the criteria to protect against the largest frequency excursion the interconnection can withstand, the contingency criteria may vary significantly between the interconnections. For example, because of its sheer size and generating capacity, the Eastern Interconnection can withstand a greater loss of resources.

Therefore, a blending of Resource Contingency Protection Criteria is recommended (table 4) for the determination of IFROs.

Table 11: Recommended Resource Contingency Protection Criteria

Interconnection	Resource Contingency	Basis	MW
Eastern	Largest Resource Event in Last 10 Years	August 4, 2007 Disturbance	4,500
Western	Largest N-2 Event	2 Palo Verde Units	2,740[46]
ERCOT	Largest N-2 Event	2 South Texas Project Units	2,750[47]

Although the size of a resource contingency that can be sustained by an interconnection should be tested through dynamic simulations, that test can currently be done only for the Western and ERCOT Interconnections.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – Dynamic simulation testing of the Eastern Interconnection Resource Contingency Protection Criteria should be conducted when the dynamic simulation models of the interconnection are capable of performing the analysis.

[45] The May 15, 2003 disturbance was a complex series of events that tripped six generators due to a protracted fault. This was not an N-1 event.

[46] Net winter ratings per Form EIA-860 reporting.

[47] Net rating from ERCOT Resource Asset Registration Form (RARF).

Comparison of Alternative IFRO Calculations

Each of the proposed resource loss criteria alternatives were compared through development of the corresponding IFROs. The following tables show the calculation of an IFRO for each alternative for the Eastern, Western, and ERCOT Interconnections. The criterion for the Québec Interconnection was kept constant throughout.

IFRO Formulae

The following are the formulae that comprise the calculation of the IFROs.

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARLPC = RLPC - CLR$$

$$IFRO = \frac{ARLPC}{MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- CC_{ADJ} is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of the Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir occurring below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RLPC is the resource loss protection criteria.
- CLR is the credit for load resources.

- ARLPC is the adjusted resource loss protection criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Determination of Maximum Delta Frequencies

Because of the limitation of measurement of the Balancing Authority-level frequency response performance using Value B, the Interconnection Frequency Obligations must be calculated in "Value B space." Protection from tripping UFLS for the interconnections based on Point C (the nadir defined as occurring between T=0 and T+12 seconds in BAL-003-1), Value B (defined as occurring from T+20 seconds to T+52 seconds), or any nadir occurring after point C, within Value B, or after T+52 seconds must be reflected in the maximum allowable delta frequency for IFRO calculations expressed as a Value B.

Table 12: Determination of Maximum Delta Frequencies

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Minimum Frequency Limit	59.500[48]	59.500	59.300	58.500	Hz
Base Delta Frequency	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R	1.000[49]	1.625	1.377	1.550[50]	Hz
Delta Frequency (DF_{CBR})[51]	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}	.018	N/A	N/A	N/A	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz

Table 12 shows the calculation of the maximum allowable delta frequencies for each of the interconnections. All adjustments to the maximum allowable change in frequency are made to include:

- adjustments for the differences between 1-second and sub-second Point C observations for frequency events,
- adjustments for the differences between Point C and Value B, and

[48] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

[49] CB_R value for the Eastern Interconnection limited to 1.0 because values lower than that indicate the Value B is lower than Point C and does not need to be adjusted. The calculated value is 0.989.

[50] Based on Québec UFLS design between their 58.5 Hz UFLS with 300 ms operating time (responsive to Point C) and 59.0 Hz UFLS step with a 20-second delay (responsive to Value B or beyond).

[51] DF_{CC}/CB_R

- adjustments for the event nadir being below the Value B (Eastern Interconnection only) due to primary frequency response withdrawal.

Recommendation – The determination for the Maximum Delta Frequencies should be calculated in accordance with the methods embodied in Table 12 – Determination of Maximum Delta Frequencies.

Largest N-2 Event

Table 13 shows the determination of IFROs based on a resource loss equivalent to the largest N-2 event in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 13: Largest N-2 Event

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	3,854	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[52]	-858	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	858	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[53]	34.8%	71.2%	48.7%	23.9%	
% of Interconnection Load[54]	0.14%	0.56%	0.45%	0.50%	

[52] IFRO =

[53] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[54] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Largest Total Plant with Common Voltage Switchyard

Table 14 shows the determination of IFROs based on a resource loss equivalent to the largest total plant with common voltage switchyard in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 14: Largest Total Plant with Common Voltage Switchyard

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	3,524	3,575	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[55]	-785	-1,127	-286	-179	MW/0.1Hz
Absolute Value of IFRO	785	1,127	286	23.9%	MW/0.1Hz
% of Current Interconnection Performance[56]	31.8%	95.6%	48.7%	23.9%	
% of Interconnection Load[57]	0.13%	0.76%	0.45%	0.50%	

[55] IFRO =

[56] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[57] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Largest Resource Event in Last 10 Years

Table 15 shows the determination of IFROs based on a resource loss equivalent to the largest resource event in the last 10 years in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Table 15: Largest Resource Event in Last 10 Years

	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	5,000	3,400	1,700	MW
Credit for LR		300	1,400		MW
IFRO[58]	-1,002	-1,721	-423	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	1,721	423	179	MW/0.1Hz
% of Current Interconnection Performance[59]	40.6%	146.0%	72.2%	23.9%	
% of Interconnection Load[60]	0.17 %	1.16%	0.66%	0.50%	

[58] IFRO =

[59] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[60] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

Recommended IFROs

Table 16 shows the determination of IFROs based on a resource loss equivalent to the recommended criteria in each interconnection. This calculation has been adjusted to include the recommended adjustment for the differences between Value B and Point C, and for the differences in measurement of Point C using 1-second and sub-second data.

Recommendation – The Interconnection Frequency Response Obligations should be calculated as shown in Table 16 – Recommended IFROs.

Table 16: Recommended IFROs					
	Eastern	Western	ERCOT	Québec	Units
Starting Frequency	59.974	59.976	59.963	59.972	Hz
Max. Delta Frequency	0.449	0.291	0.473	0.949	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	1,700	MW
Credit for LR		300	1,400		MW
IFRO[61]	-1,002	-840	-286	-179	MW/0.1Hz
Absolute Value of IFRO	1,002	840	286	179	MW/0.1Hz
% of Current Interconnection Performance[62]	40.6%	71.2%	48.7%	23.9%	
% of Interconnection Load[63]	0.17%	0.56%	0.45%	0.50%	

Special IFRO Considerations

The IFRO calculation scenarios for the Western Interconnection do not take into account intentional tripping of generation during the operation of remedial action schemes (RAS). A key example is the Pacific Northwest RAS for loss of the Pacific DC Intertie (PDCI), which trips up to 3,200 MW of generation in the Pacific Northwest when the PDCI trips, depending on the loading of the PDCI. The RAS is intended to avoid system instability, tripping generation, inserting the Chief Joseph braking resistor (for up to 30 cycles), and other reactive configuration

[61] IFRO =

[62] Current Interconnection Frequency Response Performance: EI = -2,467 MW / 0.1Hz, WI = -1,179 MW / 0.1Hz, TI = -586 MW / 0.1Hz, and QI = -750 MW/0.1 Hz.

[63] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI winter load = 36,000 MW.

changes. However, because the generation in the Pacific Norwest is some of the most responsive to frequency deviations in the Western Interconnection, the RAS also blocks frequency response by a number of generators and Balancing Authorities to avoid overloading the Pacific AC ties (such as the California–Oregon Interface (COI)).

Frequency events caused by the 3,200 MW generation trips from that RAS have not been considered historically as candidate events for the Western Interconnection calculation of frequency bias settings by the Balancing Authorities because of the response blocking. However, from an interconnection perspective, the frequency of the interconnection still must be maintained as a whole, regardless of which Balancing Authorities are responding to the event. This creates a dilemma when calculating an IFRO for the interconnection—the resultant resource loss is larger than the design loss criteria of two Palo Verde units (2,440 MW). Table 17 shows a comparison of the two resource losses in calculating the IFRO for the Western Interconnection.

Table 17: Western Interconnection IFRO Comparison

	2-PV	PNW RAS	Units
Starting Frequency	59.976	59.976	Hz
Max. Delta Frequency	0.291	0.291	Hz
Resource Contingency Protection Criteria	2,740	3,200	MW
Credit for LR	300		MW
IFRO[64]	-840	-1,101	MW/0.1Hz
Absolute Value of IFRO	840	1,101	MW/0.1Hz
% of Current Interconnection Performance[65]	71.2 %	93.4 %	
% of Interconnection Load[66]	0.56 %	0.74 %	

Using a 3,200 MW resource loss criterion in the IFRO calculation increases the obligation by 260 MW but is further complicated when that obligation is allocated to the Balancing Authorities in the interconnection; allocation of FRO to Balancing Authorities whose response is blocked by the RAS is inappropriate. Therefore, a different FRO allocation would be necessary for that IFRO.

Recommendation – NERC and the Western Interconnection should analyze the FRO allocation implications of the Pacific Northwest RAS generation tripping of 3,200 MW.

[64] IFRO =

[65] Current Interconnection Frequency Response Performance: WI = -1,179 MW / 0.1Hz.

[66] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: WI = 148,895 MW.

Comparison of IFRO Calculations

Table 18 shows a comparison of the four criteria analyzed by the TIS, as well as the criteria recommended by the NERC Resources Subcommittee (RS) in their white paper on frequency response. The table also compares the IFROs to current levels of frequency response performance[67] for each of the interconnections. A comparison is also made to IFROs adjusted to include the recommended adjustment for the differences between Value B and Point C.

Table 18: IFRO Calculation Comparison

	Eastern	Western	ERCOT	Québec	Units
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Largest N-2 Event					
Resource Loss Criteria	3,854	2,740	2,750	1,700	MW
IFRO	-858	-840	-286	-179	MW/0.1Hz
IFRO as % of Current Performance	34.8%	71.2%	48.7%	23.9%	
IFRO as % of Load[68]	0.14%	0.56%	0.45%	0.50%	
Largest Total Plant with Common Voltage Switchyard					
Resource Loss Criteria	3,524	3,575	2,750	1,700	MW
IFRO	-785	-1,127	-286	-179	MW/0.1Hz
IFRO as % of Current Performance	31.8%	95.6%	48.7%	23.9%	
IFRO as % of Load	0.13%	0.76%	0.45%	0.50%	
Largest Resource Event in Last 10 Years					
Resource Loss Criteria	4,500	5,000	3,400	1,700	MW
IFRO	-1,002	-1,716	-423	-179	MW/0.1Hz
IFRO as % of Current Performance	40.6%	146.0%	72.2%	23.9%	
IFRO as % of Load	0.17%	1.16%	0.66%	0.50%	

[67] Based on the frequency response performance calculated in the daily CERTS-EPG Automated Reliability Reports for 2011 through August 16, 2011.

[68] Interconnection projected Total Internal Demands from the 2010 NERC Long-Term Reliability Assessment: EI = 604,245 MW, WI = 148,895 MW, TI = 63,810 MW, and QI = 20,599 MW.

Table 19 compares the recommended IFROs with those recommended by the Resources Subcommittee.

Table 19: IFRO Calculation Comparison					
	Eastern	Western	ERCOT	Québec	Units
Current Interconnection Frequency Response Performance	-2,467	-1,179	-586	N/A	MW/0.1Hz
Recommended IFROs					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
IFRO	-1,692	-838	-286	-417	MW/0.1Hz
IFRO as % of Load	0.28 %	0.56 %	0.45 %	2.03 %	
RS Recommendation					
Resource Loss Criteria	4,500	2,740	2,750	1,700	MW
Base IFRO	-1,125	-548	-229	-113	MW/0.1Hz
25 % Margin	-281	-137	-57	-28	MW/0.1Hz
IFRO	-1,406	-685	-286	-141	MW/0.1Hz
IFRO as % of Load	0.23 %	0.46 %	0.45 %	0.68 %	

Allocation of IFRO to Balancing Authorities

The allocation of the IFRO to individual Balancing Authorities in a multi-Balancing Authority interconnection will be done in accordance with the "Attachment A – BAL-003-1 Frequency Response and Frequency Bias Setting Supporting Document," which can be found at:

http://www.nerc.com/docs/standards/sar/Att_A_Freq_Response_Standard_Support_Document_100611.pdf)

The process is paraphrased here for brevity.

Once the IFROs have been calculated by the ERO, the FRO for each Balancing Authority in a multi-Balancing Authority interconnection is allocated based on the Balancing Authority's annual load and annual generation to each Balancing Authority by the following formula:

$$FRO_{BA} = FRO_{Int} X \frac{AnnualGen_{BA} + AnnualLoad_{BA}}{AnnualGen_{Int} + AnnualLoad_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column C of Part II – Schedule 3.
- Annual $Load_{BA}$ is total annual load within the BAA, on FERC Form 714, column E of Part II – Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which used data from 2011. Balancing Authorities that are not FERC-jurisdictional will use the Form 714 instructions to assemble and submit equivalent data to the ERO for use in the FRO allocation process.

Balancing Authorities that elect to form a Frequency Response Sharing Group (FRSG) will calculate an FRSG FRO by summing the individual Balancing Authority FROs. Balancing Authorities that elect to form an FRSG as a means to jointly meet the FRO will calculate their FRM performance for the FRS Form 1 as follows:

- calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- jointly submit each Balancing Authority's Form 1 with a summary spreadsheet that sums each participant's individual event performance.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the interconnection remains the same and so that Control Performance Standard (CPS) limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), frequency bias setting and frequency bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised frequency bias settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- frequency bias setting
- Frequency Response Obligation (FRO)

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4 of the BAL-003-1 standard.

Frequency Response Performance Measurement

Interconnection Process

The process for detection of candidate interconnection frequency events for use in frequency response metrics is described in the ALR1-12 Metric Event Selection Process contained in Appendix W. It is paraphrased here for brevity.

Frequency Event Detection, Analysis, and Trending (for Metrics and Analysis)

Interconnection frequency events are detected through a number of systems, including:

- FNet (Frequency monitoring Network) – FNet is a wide-area power system frequency measurement system that uses a type of phasor measurement unit (PMU) known as a Frequency Disturbance Recorder (FDR). FNet is able to measure the power system frequency, voltage, and angle very accurately at a rate of 10 samplers per second. The FNet system is currently operated by the Power Information Technology Laboratory at Virginia Tech and the University of Tennessee, Knoxville. FNet alarms are received by the NERC Situational Awareness staff and contain an estimate of the size of the resource or load loss and general location description based on triangulation between FDRs.
- CERTS–EPG Resource Adequacy Tool Intelligent Alarms – The Electric Power Group (EPG) operates the Resource Adequacy (RA) tool developed under the auspices of the Consortium for Electric Reliability Technology Solutions (CERTS). The RA tool uses 1-minute frequency and area control error (ACE) SCADA data transmitted to a NERC central database. The RA tool constantly monitors frequency and produces many Smart Alarms for a number of frequency change conditions, but most useful for frequency event detection is the short-term frequency deviation alarm, which indicates when there has been a significant change in frequency over the last few minutes, typically indicating a resource loss.
- CERTS–EPG Frequency Monitoring and Analysis (FMA) Tool – EPG also developed and operates the FMA tool that allows rapid analysis of frequency events, calculating the A, B, and C values for a frequency event in accordance with parameters set by the Frequency Working Group (FWG). Event selection criteria are further discussed in Appendix E of this report.

Those three systems are used in combination by NERC staff to detect and collect data about frequency excursions in the four North American interconnections. The size of resource losses is verified with the Regional Entities for events where FNet estimates of resource loss meet the following criteria:

- Eastern: >1,000 MW (60 mHz excursion)
- Western: >700 MW (80 mHz excursion)
- ERCOT: >450 MW (100 mHz excursion)

Events that are detected and meet the ALR1-12 metric criteria are then considered to be "candidate events" and are used by NERC to calculate interconnection frequency response metrics and trends. Those candidate events are also presented to the Frequency Working Group for consideration to be used as events for calculation of Balancing Authority frequency response and bias setting calculations in accordance with NERC Standard BAL-003-1.

Ongoing Evaluation

The process for detection of frequency events and the calculation of Values A, B, and C and the associated interconnection level metrics will undergo constant review in an effort to improve the process. NERC staff and the Frequency Working Group will perform that review at least annually.

Recommendation –NERC staff and the Frequency Working Group should annually review the process for detection of frequency events and the method for calculating A and B Values and Point C. The associated interconnection frequency event database, methods for calculating interconnection metrics on risks to reliability, the associated probabilities, and the calculation of the IFROs using updated data should also undergo review in an effort to improve the process. Throughout this process, NERC should strive to improve the quality and consistency of the data measurements.

Balancing Authority Level Measurements

A statistical analysis and evaluation was performed on field trial data with similar sample sizes to those specified in the draft Standard BAL-003-1 Frequency Response and Frequency Bias Setting. Field trial data was provided on FRS Form 1 for 2011 for 60 Balancing Authorities on the Eastern and Western Interconnections; the analysis was not performed for either of the single Balancing Authority interconnections, (i.e., ERCOT or Québec). Of the 60 Balancing Authorities that provided data, only 50 provided data of sufficient quality to be used in the analysis. Balancing Authorities that were excluded provided frequency data that was either obviously incorrect (i.e., frequency data in hertz instead of change in hertz) or frequency data that was uncorrelated to the frequency measured in an interconnection.

To protect the confidential nature of the data, the Form 1 data was normalized by dividing the change in actual net interchange by the Frequency Response Obligation (FRO) for each Balancing Authority, based on Interconnection Frequency Response Obligations (IFROs) of -1,215 MW/0.1 Hz and -836 MW/0.1 Hz for the Eastern and Western Interconnections, respectively.[69] This normalization method converts all of the data from the actual frequency response of the Balancing Authority to a per-unit frequency response value where 1.0 indicates that the frequency response is exactly equal to the Balancing Authority's FRO. The process also required the development of the some of the data that would appear on the equivalent of the CPS2 Bounds Report under this revised standard. The required data was extracted from FERC Form 714 reports for the year 2009 and was estimated for those Balancing Authorities that did

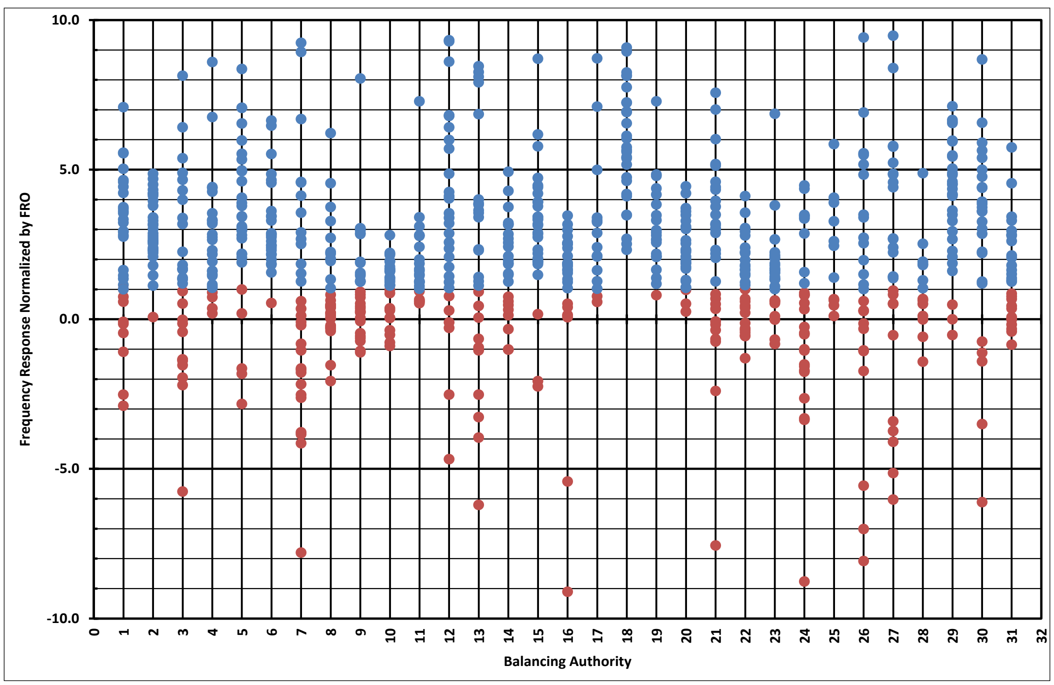
[69] As recommended by the Project 2007-12 Frequency Response Standards Drafting Team during the May 2012 Frequency Response Technical Conferences.

not submit 714 reports from equivalent data based on other sources. The validity of this analysis is not dependent upon the accuracy of the FRO estimates. It is only necessary for these estimates to be close to the actual values for firm conclusions to be drawn from the results and put the results in the proper context. Once the FROs were estimated for all of the Balancing Authorities on the Eastern and Western Interconnections, they were transcribed onto the FRS Form 1 for each Balancing Authority included in the analysis.

Single-Event Compliance

The question was posed whether or not a Balancing Authority's compliance with the proposed BAL-003-1 standard should be measured on each event, through use of the mean, median, or a regression analysis for a 12-month period. The variability of the measurement of frequency response for an individual Balancing Authority for an individual disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Balancing Authorities' performance disturbance events were normalized and plotted for each Balancing Authority on the Eastern and Western Interconnections.

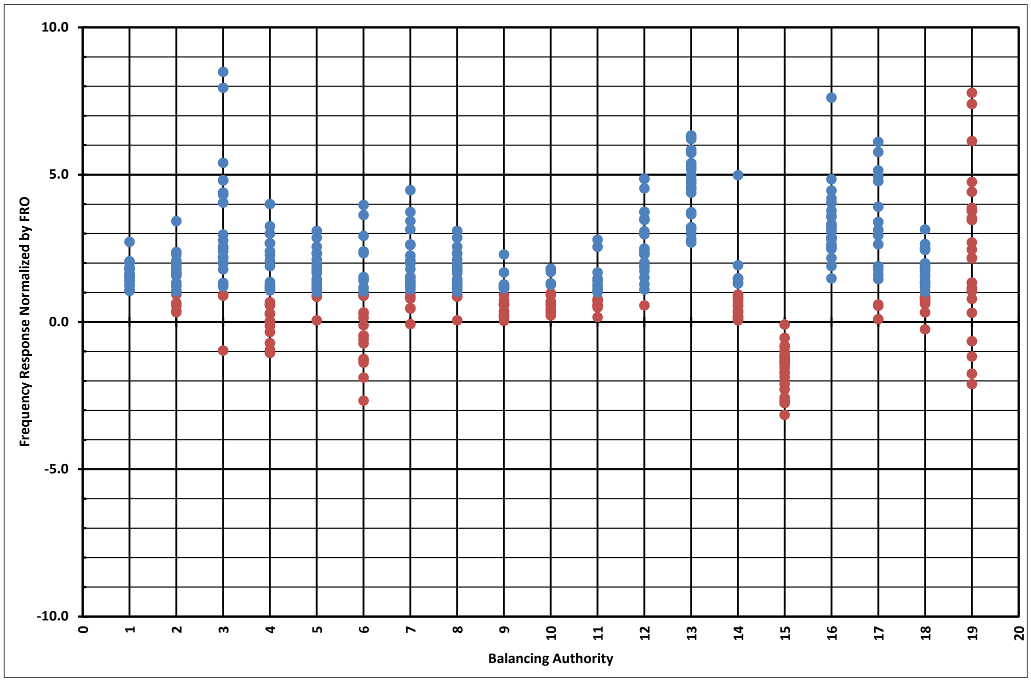
Figure 34: 2011 Normalized Frequency Response Events by BA Eastern Interconnection



On Figures 34 and 35, events that had a measured Balancing Authority's frequency response above its FRO were shown as blue dots, and events that had a measured frequency response below its FRO were shown as red dots.

Analysis of this data indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in the charts in Appendix 1. Based on the field trial data provided, only three out of 19 Balancing Authorities in the sample (16%) would be compliant for all events with a standard based on a single event measure on the Western Interconnection. Only one out of 31 Balancing Authorities in the sample (3%) would be compliant for all events with a standard based on a single-event measure on the Eastern Interconnection.

Figure 35: 2011 Normalized Frequency Response Events by BA Western Interconnection



Finding – Analysis of the field trial data indicates that a single-event-based compliance measure is unsuitable for compliance evaluation when the data has a large degree of variability.

Recommendation – Balancing Authority compliance with BAL-003-1 should not be judged on a per-event basis. Doing so would cause almost 90% of the Balancing Authorities to be out of compliance.

Balancing Authority Frequency Response Performance Measurement Analysis

Data provided by the Balancing Authorities from the field trial were also analyzed to determine: 1) if the sample size minimum of 20–25 frequency events, as specified for FRM calculation of the draft BAL-003-1 standard, is sufficient to provide stable measurements results; and 2) which of the three candidate FRM measurement methods is most appropriate. These analyses were carried out using the normalized data provided by a number of Balancing Authorities during the field trial.

Event Sample Size

Previous studies have recommended a sample size sufficient to provide a stable measure of frequency response of 20–25 events. These previous studies were performed on limited data and a limited number of Balancing Authorities. The field trial data set is sufficiently large to allow conclusions to be drawn with respect to that sample size recommendation specified for FRM calculation in the draft standard.

Review of the full set of graphs (Appendix H) indicates that the outlier problem, as previously described, did not present itself. There were no Balancing Authorities that had a small degree of variability in the measured single-event frequency response for most of the events that contained a few outliers.

The variability appeared similar for all events for each Balancing Authority, which indicates that the sample size of 20–25 events was sufficient to stabilize the result and eliminate any undue influence from potential outliers. In those Balancing Authorities with large variations in measured single-event response, the sample size was large enough that no single outliers unduly influenced the result. Balancing Authorities with large measurement variation still had enough samples to mitigate the risk associated with outliers. This demonstrates that the sample size chosen was sufficient to stabilize all three methods of measuring FRM. Therefore, it can be concluded that none of the methods are unduly influenced by outliers and the selection of the measurement method should be based on other factors.

Finding – Analysis of data submitted by the Balancing Authorities during the field trial confirms that the sample size selected (a minimum of 20–25 frequency events) is sufficient to stabilize the result and alleviate the perceived problem associated with outliers in the measurement of Balancing Authority frequency response performance.

Measurement Methods – Median, Mean, or Regression Results

All of the normalized data were analyzed using all three candidate methods for measuring FRM.

> **median** – Median is the numerical value separating the higher half of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution from the lower half. The median of a finite list of numbers is found by arranging all the observations from lowest value to highest value and picking the middle one. When the number of observations is even, there is no single middle value; the median is arbitrarily defined as the mean of the two middle values.
>
> In a sample of data, or a finite population, there may be no member of the sample whose value is identical to the median (in the case of an even sample size), and, if there is such a member, there may be more than one so that the median may not uniquely identify a sample member. Nonetheless, the value of the median is uniquely determined with the usual definition. A median is also a central point that minimizes the arithmetic mean of the absolute deviations. However, a median need not be

uniquely defined. Where exactly one median exists, statisticians speak of "the median" correctly; even when no unique median exists, some statisticians speak of "the median" informally.

The median can be used as a measure of location when a distribution is skewed, when end values are not known, or when one requires reduced importance to be attached to outliers; e.g., because they may be measurement errors. A median-unbiased estimator minimizes the risk with respect to the absolute-deviation loss function, as observed by Laplace.[70] For continuous probability distributions, the difference between the median and the mean is never more than one standard deviation. Calculation of medians is a popular technique in summary statistics and summarizing statistical data, since it is simple to understand and easy to calculate. It also gives a measure that is more robust in the presence of outlier values than the mean.

mean – Mean is the numerical average of a one-dimensional sample, a one-dimensional population, or a one-dimensional probability distribution. A mean-unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function, as observed by Gauss.[71] The mean is more sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

linear regression – Linear regression is the linear average of a multi-dimensional sample, or a multi-dimensional population. A linear regression unbiased estimator minimizes the risk (expected loss or estimate error) with respect to the squared-error loss function in multiple dimensions, as observed by Gauss.[72] The linear regression is also sensitive to outliers for the very reason that it is a better estimator; it minimizes the squared-error loss function.

Important Considerations

The following issues are important to consider with respect to the selection of the best method for measuring frequency response.

two-dimensional measurement – Two-dimensional measurement of frequency response provides the best representation of the change in MWs divided by the change in frequency and is used to estimate the frequency bias setting, which indicates the frequency response in MWs provided at actual frequency as compared to scheduled frequency.

non-linear attribute of frequency response – The non-linear attribute of frequency response has been demonstrated on all of the North American interconnections and is an important consideration in the representation of frequency response.

[70] An absolute-deviation loss function is used to minimize the risk of estimate error when dealing with uniform distributions. Appendix 3 provides a description of Uniform Distributions and a derivation of the median.

[71] A squared-error loss function is used to minimize the risk when dealing with normal (Gaussian) distributions. Appendix 4 provides a description of normal (Gaussian) distributions and a derivation of the mean.

[72] Appendix H provides a derivation of the linear regression.

single best estimator – A single best estimator of frequency response is a necessary result for use in compliance evaluation.

linear system – A linear system[73] is assumed in the development of the individual Frequency Response Obligation for each Balancing Authority on a multiple Balancing Authority interconnection and is used to distribute the Interconnection Frequency Response Obligation among the Balancing Authorities on that interconnection. If the system is non-linear,[74] then it cannot be assumed that the total required Interconnection Frequency Response Obligation will be achieved when all Balancing Authorities provide their individual Frequency Response Obligations.

bi-modal distributions – Bi-modal distributions occur whenever a reconfiguration of Balancing Authorities occurs within a compliance year. Unless the method chosen can correctly represent bi-modal distributions, reconfigured Balancing Authorities cannot be effectively measured for compliance.

quality statistics – Quality statistics should be available for use in compliance evaluation. Frequency response is used to determine compliance with minimum provision of the Balancing Authority's obligation for providing its share of frequency response for the interconnection. When using a measure for compliance, one must ensure that the measure fairly represents the Balancing Authority's performance. There is still a presumption that an indication of non-compliance should not occur due to pure chance.

reducing influence of noise – Reducing influence of noise in the data is considered an important attribute in the measurement method. All measurements of frequency response will be affected by noise in the measurement process.

reducing influence of outliers – Reducing influence of outliers in the data is considered the most important attribute in the measurement method. All measurements of frequency response will be affected by true outliers. The risk associated with the reduction in the influence of outliers is that valid information about the measure is also lost when an outlier reduction method is used.

ease of calculation and familiar indicators – Ease of calculation and familiar indicators are important considerations for communication and to promote ease of understanding by the industry.

Appendix H presents the series of graphs indicating results for each Balancing Authority. Each graph shows all of the individual data points use to determine the median, mean, and regression lines.

[73] A linear system is a system in which the sum of the parts is equal to the whole.
[74] A non-linear system is a system in which the sum of the parts is not equal to the whole.

The median line is green, the mean line is blue, and the regression line is red. The value of the normalized frequency response (vertical axis) where the line intercepts the value of frequency (horizontal axis) at a value of 0.1 Hz indicates compliance. Values above 1.0 indicate an FRM above the FRO, and values below 1.0 indicate an FRM below the FRO.

Figure 36 shows an example of a Balancing Authority with a small degree of variability in the measured frequency response for each individual event.

Figure 36: BA with Small Degree of Variability in Measured Frequency Response

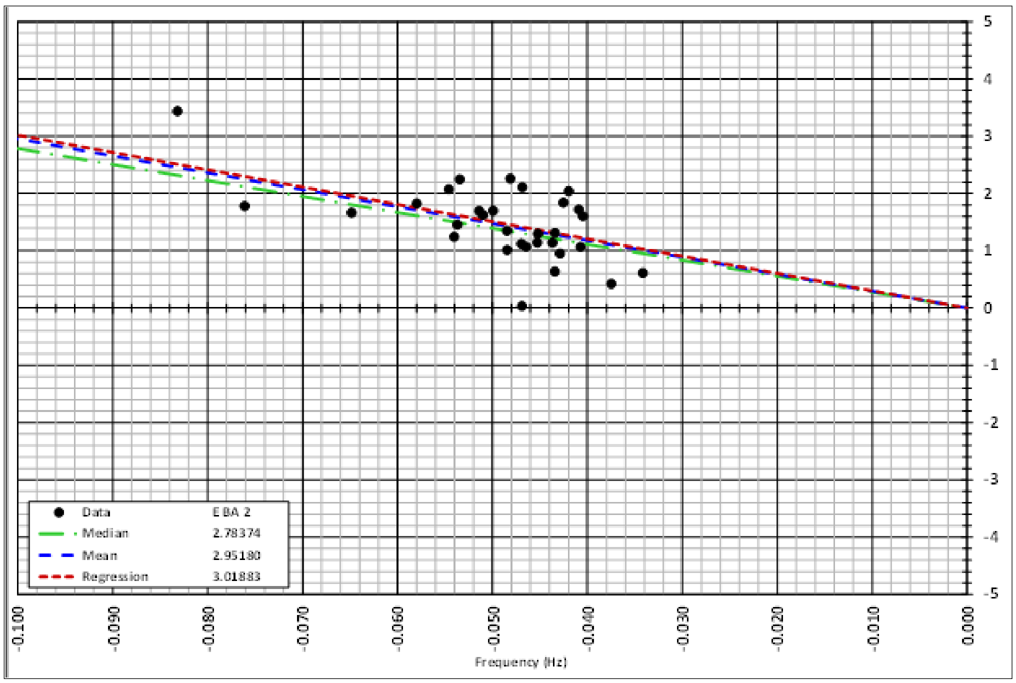
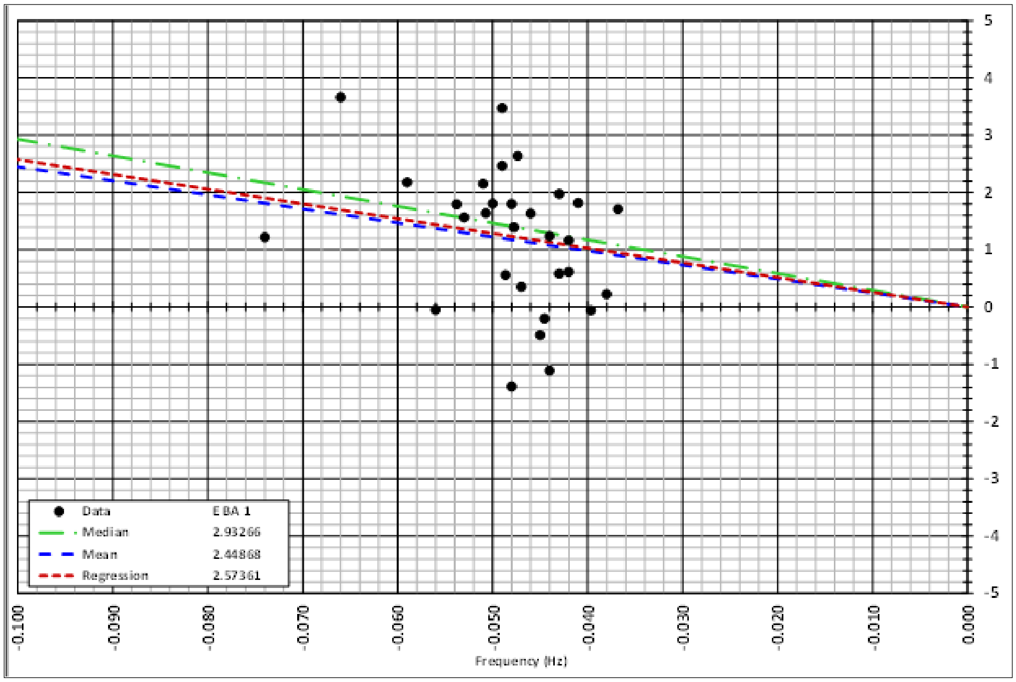


Figure 37 shows an example of a Balancing Authority with a large degree of variability in the measured frequency response for each individual event.

During the analysis, the graphs appeared to show that the regression provided a higher estimate of FRM than the median. Consequently, a comparison was made between the FRM as measured by the median and the FRM as measured by the regression. The results of the regression analysis demonstrate a performance for all samples that is 0.087% of their FRO higher than the median's performance on the Eastern Interconnection and 0.117% of their FRO higher than the median's performance on the Western Interconnection. In an unbiased analysis, one would expect the median and regression to yield the same result. This indicates there is an unknown statistical bias affecting the results of the analysis.

Figure 37: BA with Large Degree of Variability in Measured Frequency Response

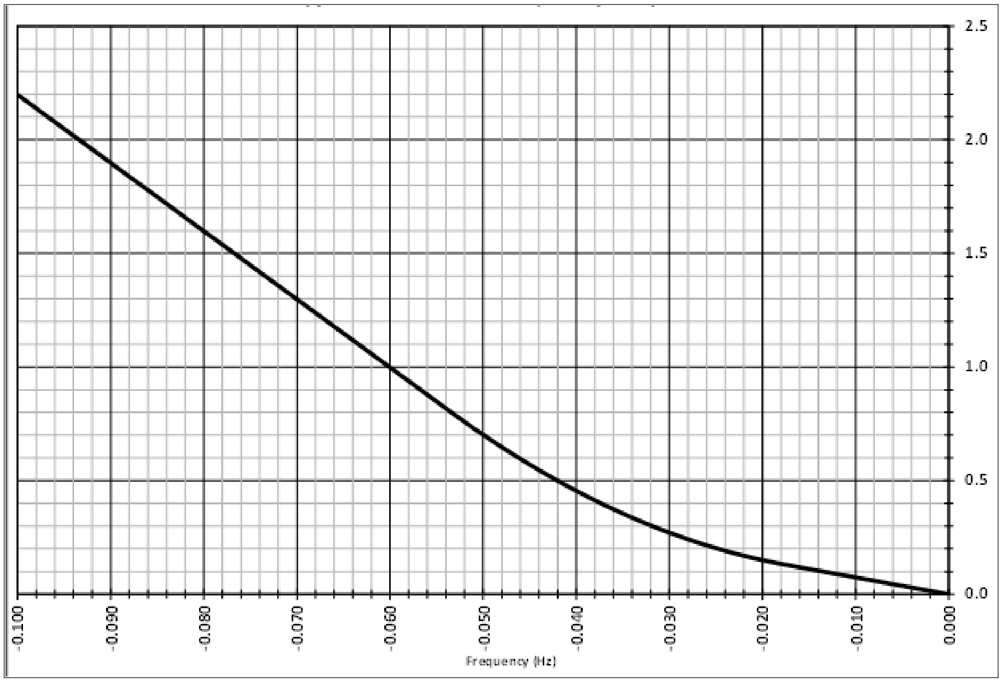


The bias causing the difference between the median and regression results can be explained by an attribute of frequency response. As the frequency deviation increases for larger disturbance events, the frequency response increases, but it does so disproportionately, shown in figure 38. This attribute of frequency response has been demonstrated in technical papers.[75] It has also been implemented in the variable frequency bias settings used by ERCOT, BPA and BC Hydro. In simple terms, the regression includes the effect of this non-linear attribute and the median does not.

The regression accommodates the disproportion on the slope of the regression line. In this case the effect tends to be upward—ever bigger MWs per increment in size of larger frequency error. The median is biased against any disproportionate increase in response per increase in size of frequency error as part of the median's blindness to outliers. The median will give no credit for the ever-growing amount of MWs deployed per added increment in size of frequency error. All the median does is count the number of MW responses regardless of size and, to represent all the MW responses, choose the one that occurred half-way in the sequence of decreasingly negative and increasingly positive frequency errors. Therefore, the median underestimates the FRM because it cannot evaluate the non-linear attribute correctly. It does not see or notice that attribute at all through its blinders regardless of numerical order or placement in a sequence. Regression is the only measurement method that captures the non-linear frequency response correctly.

[75] Hoffman, Stephen P., Frequency Response Characteristic Study for ComEd and the Eastern Interconnection, Proceedings of the American Power Conference, 1997. Kennedy, T., Hoyt, S. M., Abell, C. F., Variable, Non-linear Tie Line Frequency Bias for Interconnected Systems Control, IEEE Transactions on Power Systems, Vol. 3, No. 3, August 1988.

Figure 38: Typical Non-Linear Frequency Response



The advantages of each method of measurement are presented in Table 20 – Median, Mean and Regression Comparison. The alphabetic key is below.

Table 20: Median, Mean, and Regression Comparison

Attribute	Median	Mean	Regression
Provides two-dimensional measurement	A	A	Yes
Represents non-linear attributes	B	B	Yes
Provides a single best estimator (single value)	C	Yes	Yes
Is part of a linear system		Yes	Yes
Represents bi-modal distributions	D	Yes	Yes
Quality statistics available	E	Yes	Yes
Reducing influence of noise	Yes (F)		Partial (G)
Reducing influence of outliers	Yes		Partial (H)
Easy to calculate	Yes	Yes	I
Familiar indicator	Yes	Yes (J)	No
Currently used as the measure in BAL-003-1	No	Yes	No

A. Neither median nor mean can evaluate the two-dimensional nature of frequency response.

B. Neither median nor mean can capture the non-linear attribute of frequency response. Both underestimate the typical non-linear frequency response.

C. Median is arbitrarily defined as the average of the two central values when there is an even number of values in the data set. The decision to further constrain this central range of values to a single value that is the average of the ends of that range is unsupported by any mathematical construct. It is only the desire of those looking for simplicity in the result that supports this singular definition of median.

D. The median fails to provide a valid estimate of frequency response when the distribution of frequency event responses is bi-modal due to Balancing Authority reconfiguration or changes in responsibility for control such as partial-period overlap of supplemental control.

E. The median fails to provide any methods to determine the quality, significance, or confidence associated with the measure.

F. The median reduces the influence of noise in the data, but that noise reduction comes with the cost of eliminating the availability of any quality statistics.

G. Linear regression provides a result that weights the data according to the change in frequency. Since the noise in the data is independent of change in frequency, linear regression provides a method superior to the mean for reducing the influence of noise in the resulting estimate of frequency response.

H. Linear regression is less sensitive to outliers and large data errors than the mean.

I. Linear regression is more complex and requires more effort to calculate, but that additional effort is small when the evaluation process has been automated.

J. Mean is currently used as the measure in the proposed draft BAL-003-1 standard.

After consideration of the mitigating effects of the sample size with respect to outliers, the linear regression method is the preferred method for calculating the frequency response Measure (FRM) for Balancing Authorities for compliance with proposed NERC Standard BAL-003-1 – Frequency Response.

Recommendation – Linear regression is the method that should be used for calculating Balancing Authority Frequency Response Measure (FRM) for compliance with Standard BAL-003-1 – Frequency Response.

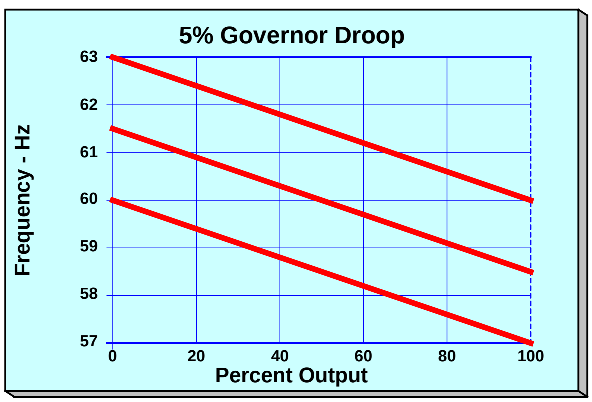
Role of Governors

Deadband and Droop

Turbine-generator units use turbine speed control systems, called governors, to control shaft speed by sensing turbine shaft speed deviations and initiating adjustments to the mechanical input power to the turbine. This control action results in a shaft speed change (increase or decrease). Since turbine-generators rotate at a variety of speeds, outside the power plant it is more appropriate to generally relate shaft speed to system frequency and throttle valve position to generator output power (MW).

The expected response of a turbine-generator's governor to frequency deviations is often plotted on what is known as a governor droop characteristic curve or a droop curve. The curve shows the relationship between the generator output and system frequency. The curve droops from left to right. Simply stated, as the frequency decreases, the generator's output will increase in accordance with its size.

Figure 39: Sample Droop Characteristic Curve



Droop settings on governors are necessary to enable multiple generators to operate in parallel while on governor control while not competing with each other for load changes. Droop is expressed as a percentage of the frequency change required for a governor to move a unit from no-load to full-load or from full-load to no-load. Prior to 2004, NERC Operating Policy 1, Generation Control and Performance, recommended generators with governor control (typically 10 MW and larger) to have a droop setting of 5% for steam turbine (and 4% for combustion turbines, although not explicitly stated in the policy). This means that a 3 Hz (5% of 60.00 Hz) change in system frequency is required to move a generator across its full range. Normally governors respond only to substantial frequency deviations.

Guidelines of the 2004 NERC Operating Policy 1, Generation Control and Performance, section C, stated:

1. Governor installation – Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.
2. Governors free to respond – Governors should be allowed to respond to system frequency deviation unless there is a temporary operating problem.
3. Governor droop – All turbine-generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, at a minimum, be fully responsive to frequency deviations exceeding ±0.036 Hz (±36 mHz).
4. Governor limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

Within the Frequency Response Initiative, NERC is considering modifications to those parameters based on the recent advances in frequency response performance in ERCOT and revised governor control parameters.

In 2010, NERC conducted a survey of governor status and settings through Generator Owners and Generators Operators. The results of that survey are summarized in the Generator Governor Survey section of this report. A complete set of the summary graphics of the survey is contained in Appendix K.

ERCOT Experience

The general decline in primary frequency response in all interconnections has prompted regulatory entities to address the issue. Electric grids such as the one in Texas are especially sensitive to frequency regulation and response due to their relatively small overall interconnected capacity compared to the other interconnections. The Texas Regional Entity (TRE) is actively working on a regional standard for frequency regulation.

Frequency Regulation

Electric grid frequency regulation is attained by the response of the turbine governors to deviations from nominal synchronous speed, the operation of the boilers-turbine controls in response to the frequency change, and the actions of the dispatching system.

Frequency regulation success for any given boiler-turbine plant depends on many factors, primarily:

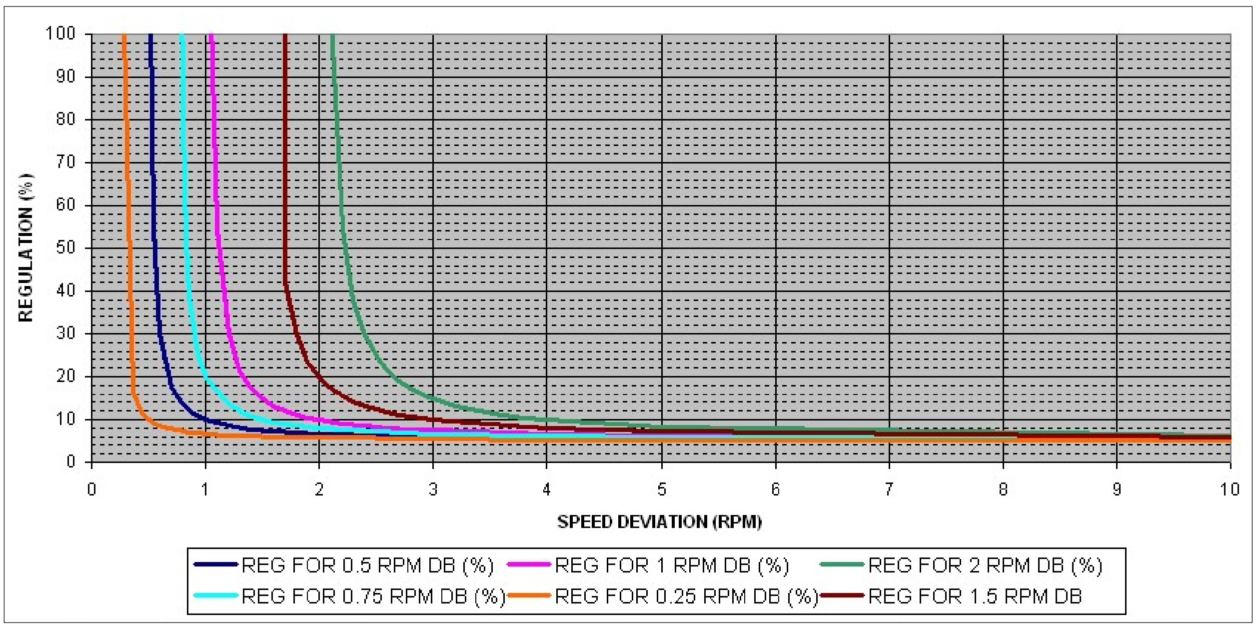
- steady state and dynamic stability of the unit
- load following capability
- linearization of turbine governor valves' steam flow characteristics
- proper calibration and coordination of the boiler and turbine frequency regulation parameters

- proper high and low limiting of the boiler and turbine frequency regulation based on unit conditions
- proper dispatching actions to restore the frequency to its normal operating value

Another factor that influences a unit's capability for frequency regulation is the available boiler energy storage. The larger the storage, the less the initial pressure drop caused by the quick opening of the governor valves, and the better the initial unit frequency regulation.

The standard speed regulation setting for the turbine governors of the boiler-turbine generating units is 5%. This is a ±5% change from rated speed (0.05*3,600 = 180 RPM), which causes the turbine governor to change its valves' position demand ±100 percent. It is also generalized industry practice to add a small deadband (DB) to the calibration of the governor speed error bias in order to minimize the movement for very small speed deviations. The selection of the DB affects the fidelity of the regulation, as shown in figure 40.

Figure 40: Regulation versus RPM Deadbands



The regulation curves of figure 40 are for the noted speed regulation at constant pressure. They are calculated by developing the equation ΔGVD= f (ΔRPM) for each DB, where ΔGVD is the change in the turbine Governor Valve Demand as a function of the change in RPM.

Knowing the ΔGVD for any given ΔRPM enables the regulation calculation via the equation:

$$REG (\%) = (100 * \Delta RPM/\Delta GVD)*(100/3,600)$$

ERCOT Nodal Operating Guides Section 2 has specific requirements for governor deadband settings. The maximum allowable deadband is ±0.036 Hz, which has been the industry standard for mechanical "fly-ball" governors on steam turbines for many years. With the development of energy markets in the early 2000s, generators with electronic or digital governors began implementing this same deadband in their primary frequency response implementation. Unfortunately, the Guides were not clear on how to implement the droop curve at the deadband. Since the Guides required 5% droop performance, many generators introduced a "step function" or modified "step" once the deadband was reached in order to achieve near 5% droop performance outside the deadband.

As can be seen in figure 40, a 2 rpm deadband on a 3,600 rpm turbine is equivalent to +/-0.033 Hz. Based on the corresponding droop (regulation percent) for this deadband, a generator's performance to typical frequency deviations during disturbances would be much greater than 5% without some "step" function. These governor settings resulted in an abnormal frequency profile for the interconnection.

Figure 41: Frequency Profile for March and September 2008 (in 5 mHz bins)

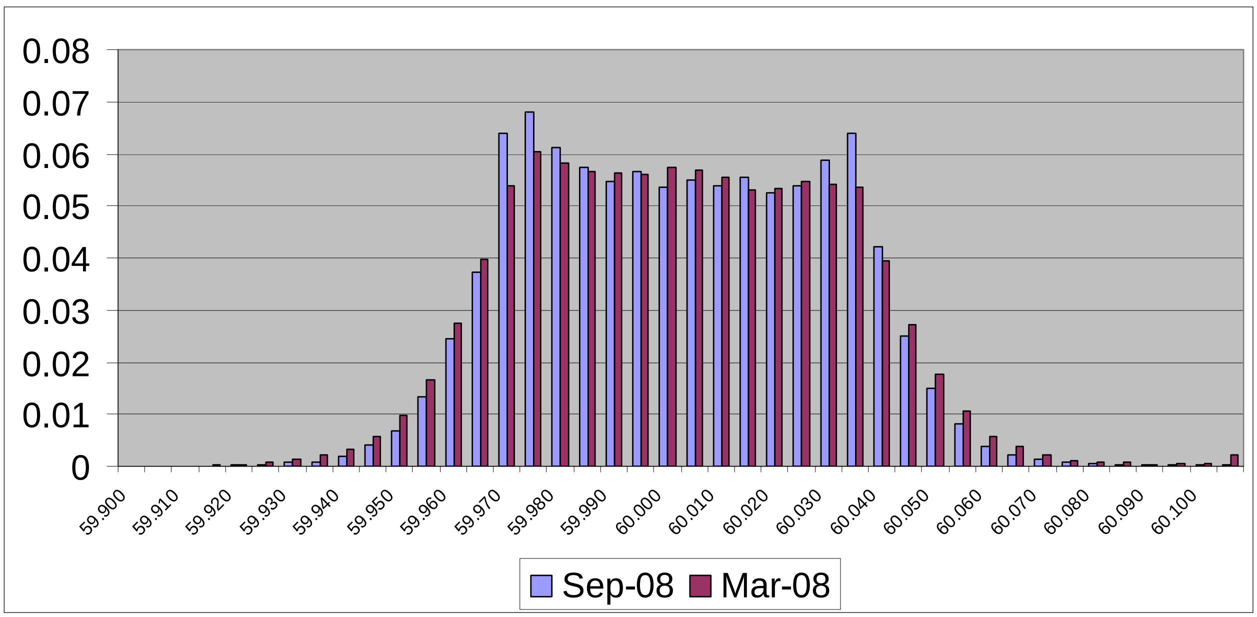
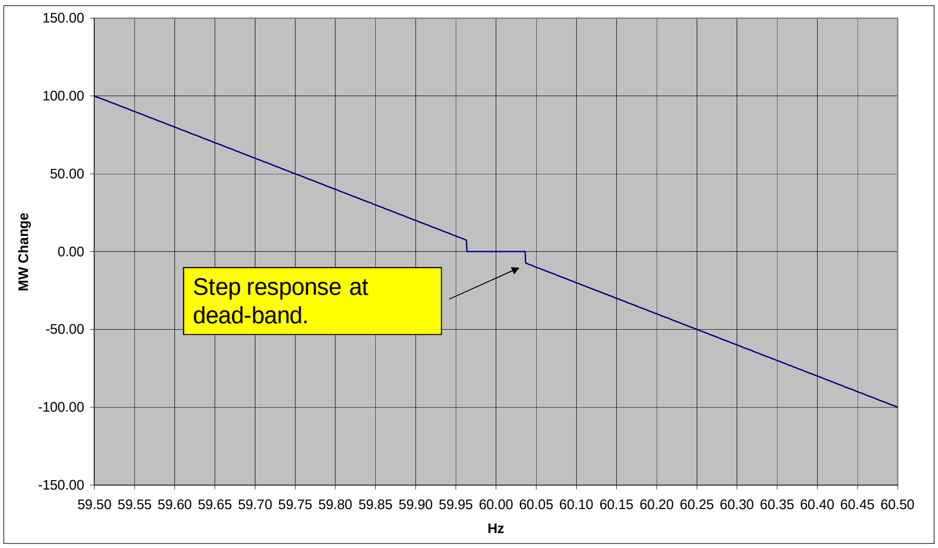


Figure 41 is the ERCOT frequency profile for March and September of 2008. It is clear that the "flat top" of the profile is centered on the ±0.036 Hz deadband. This flat frequency profile created significant problems because frequency spent as much time at the governor deadband points as it did at any point in between. This made it difficult to employ Frequency Regulation to correct frequency to 60 Hz, and for ERCOT to meet the NERC BAL-001-0 — Real Power Balancing Control Performance Requirement 1 (aka, CPS1), since ERCOT had an epsilon-1 limit of 0.030 Hz. The frequency profile also contributed to generator instability at the deadbands with the implementation of the various "step" functions in the governors.

If generators that had implemented governor step functions were to be electrically separated from the grid during an islanding event, they would experience extreme instability. This would be caused by the governor providing excessive frequency response to the island to small generation load imbalances, resulting in large frequency swings and unit instability.

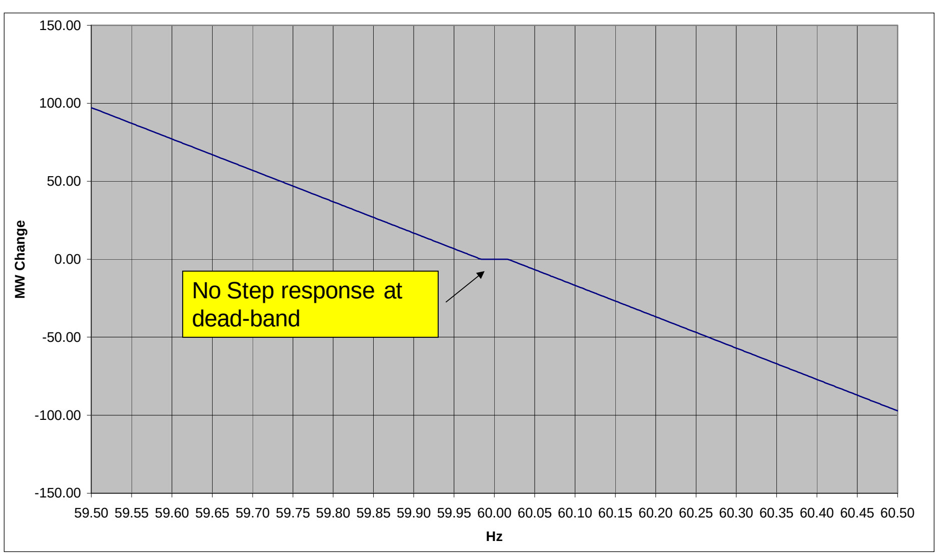
The ERCOT Performance Disturbance and Compliance Working Group (PDCWG) became increasingly concerned about the frequency instability and the realization of the risk of the step function in the governors (see figure 42). Because of their analysis, a member of the PDCWG discussed the issues with one large generating facility that was willing to try different deadband settings along with a specific droop curve implementation. This implementation required a straight linear curve from the deadband to full range of the governor, eliminating any step function shown in figure 43.

Figure 42: Frequency Response of 600 MW Unit ±36.0 mHz Deadband and Step Response



After brief testing of a number of different deadbands, a 1-rpm deadband (± 0.01666 Hz) was chosen. Four turbine governors were set in this manner on November 3, 2008 (about 2,500 MW capacity or 7.5% of the average grid capacity in November).

Figure 43: Frequency Response of 600 MW Unit ±16.67 mHz Deadband and No-Step Response



The possibility of leaving the deadband at ±0.036 Hz and just eliminating the stepped droop response was considered. Analysis showed that the droop performance at 59.900 Hz would be around 7.72% with a ±0.036 Hz deadband but only 5.97% droop with the ±0.0166 Hz deadband. That difference increases at 59.950 Hz, with a 17.64% droop performance for the ±0.036 Hz deadband and a 7.46% droop performance for the ±0.0166 Hz deadband. However, without the primary frequency response of the lower deadband, the frequency profile would return to the “flat top” frequency profile spanning the ±0.036 Hz deadbands, which is a less reliable state (less stable) for the interconnection. Also, with the larger deadband the interconnection or Balancing Authority may not have been able to meet the minimum frequency response requirements.

Turbine-Generator Performance with Reduced Deadbands

The general purpose for using governor deadbands is to minimize generator movement due to frequency regulation. In an interconnection where generators have various deadband settings, the diversity of settings creates diversity in responses to frequency changes. However, when a majority of the generators in an interconnection set the deadband the same and with a step function, the diversity of responses disappears, and frequency will move to the deadband frequently as demonstrated in the profile in figure 41. When the frequency exceeds the deadband, all units react with a stepped response simultaneously.

The amount of generator movement expected for a specific set of deadband settings can be compared by calculating the MW-minute average movement of a hypothetical generator exposed to actual measured frequency using the different governor settings.

Table 21 compares the movement of two generators with different governor settings: one with a ±0.036 Hz deadband and droop step function, and one with a ±0.01666 Hz deadband and no droop step function.

Table 21: Comparison of MW Movement for Response of Different Governor Settings

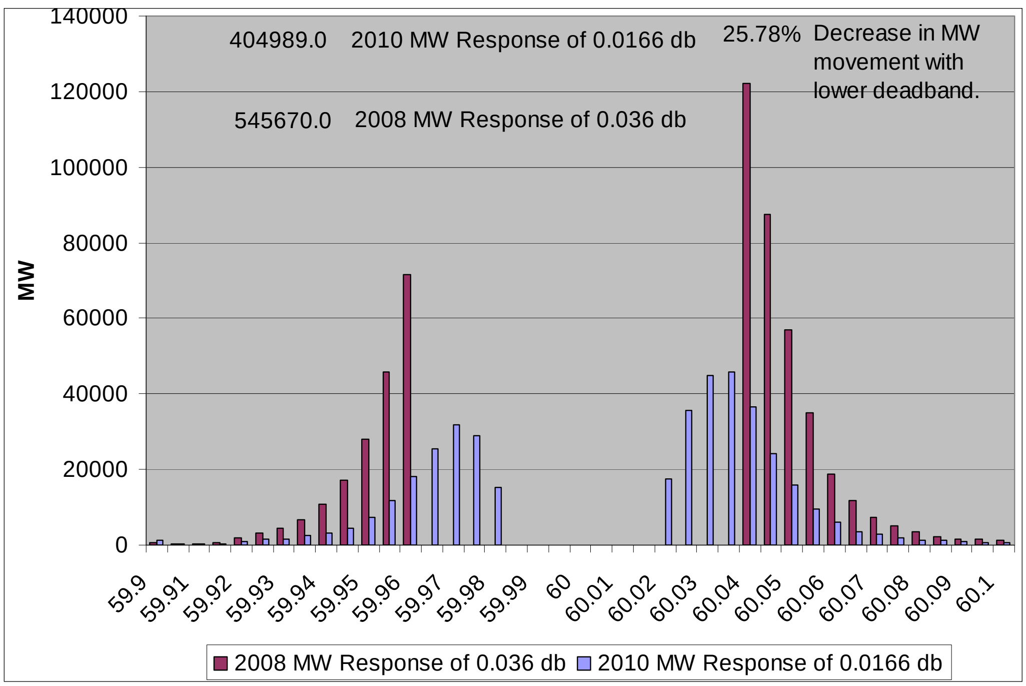
	±0.036 Hz Deadband with Droop Step Function	±0.01666 Hz Deadband with No Droop Step Function	Percent Increase for Smaller Deadband
2008 Frequency Profile	662,574.0 MW-min.	893,164.2 MW-min.	34.80%
2009 Frequency Profile	446,244.0 MW-min.	692,039.8 MW-min.	55.08%

Using the 2008 1-minute average frequency data, the generator with the lower deadband would have had 893,164.2 MW-minutes of primary frequency response while the generator with the larger deadband unit would have had 662,574.0 MW-minutes of primary frequency response. This is a 34.80% increase in movement for the lower deadband generator.

However, if the exact same comparison is made for ERCOT frequency data from 2009, where the new deadbands had an actual impact on frequency, the following observation scan be made. The lower deadband generator would have had 692,039.8 MW-minutes of primary frequency response compared to the larger deadband generator with 446,244.0 MW-minutes, a 55.08% increase in movement for the lower deadband. One observation is that the MW-minute movement of the lower deadband generator is only 4.45% higher than the movement of the larger deadband generator of the previous year (692,039.8 MW-minutes versus 662,574.0 MW-minutes).

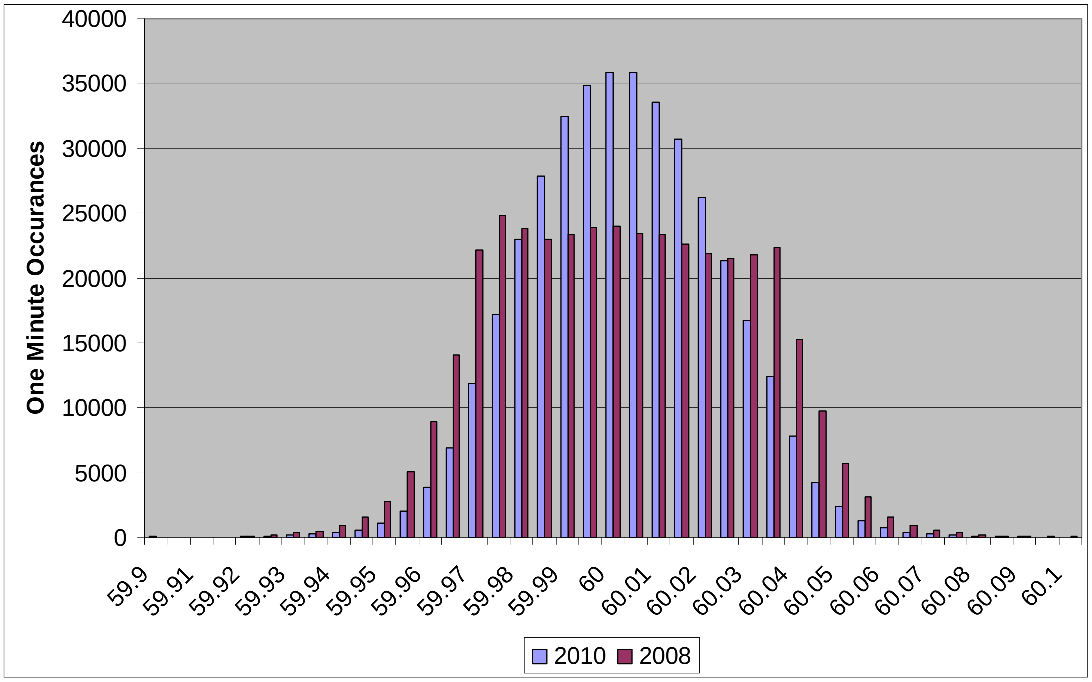
Having the lower deadband in service for the entire year greatly reduced the frequency movement of the interconnection and reduced the primary frequency response movement as well. The lower deadband generator MW-minute movement decreased 201,124.4 MW-minutes, or 22.518%, between 2008 and 2009. This indicates the reduced impact on the generator movement with the smaller deadband and the non-step governor droop implementation when the governor becomes active, as compared to the "step" implementation.

Figure 44: MW-Minute Movement of a 600 MW Unit with 5% Droop



This benefit is further emphasized by the comparison in Figure 44, which shows the response of a theoretical 600 MW unit for the 2008 ERCOT frequency profile with a ±0.036 Hz deadband versus the same unit with a ±0.01666 Hz deadband for the 2010 frequency profile. Using the lower deadband, there is a savings of 140,641 MW-minutes of regulation movement because there were a larger number of generators using the ±0.01666 Hz deadband in 2010, which greatly influenced the frequency profile. Figure 45 shows a comparison of the actual January–September ERCOT frequency profiles for 2010 and 2008. The profile changed from a flat response between the ±0.036 Hz deadband to a more normal distribution.

Figure 45: ERCOT 2010 versus 2008 Frequency Profile (Jan.–Sept.)



Conclusion – The benefits of using the smaller ±0.01666 Hz deadband coupled with a non-step governor droop implementation results in the following:

- improved frequency response for small disturbances
- generators responding more often in smaller increments, saving fuel and wear and tear on turbines
- more stable operation when near boundary conditions of deadbands

Recommendation – NERC should embark immediately on the development of a Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability. That guideline should address appropriate parameters for:

Existing generator fleet – In order to retain or regain frequency response capabilities of the existing generator fleet, adopt:

deadbands of ±16.67 mHz,

droop settings of 3%-5% depending on turbine type,

continuous, proportional (non-step) implementation of the response,

appropriate operating modes to provide frequency response, and

appropriate outer-loop controls modifications to avoid primary frequency response withdrawal at a plant level.

Other frequency-responsive resources – Augment existing generation response with fast-acting electronically coupled frequency responsive resources, particularly for the arresting and rebound periods of a frequency event:

contractual high-speed demand-side response,

wind and photo-voltaic – particularly for over-frequency response,

storage – automatic high-speed energy retrieval and injection, and

variable speed drives – non-critical, short time load reduction.

Generator Governor Survey

On September 9, 2010, NERC issued a Generator Governor Information and Setting Alert (the alert) recommending that Generator Owners (GOs) and Generator Operators (GOPs) provide information and settings for turbine governors for all generators rated at 20 MVA or greater, or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind farms, PV farms, etc.). The alert was issued as a recommendation to industry, which requires reporting obligations (as specified in Section 810 of the Rules of Procedures) from industry to NERC and, subsequently, from NERC to FERC. Balancing Authorities in North America were the only functional group required to respond to this alert. A copy of the survey instructions is located in Appendix J of this report.

The survey requested three types of information:

1. policies on installation and maintenance, and testing procedures and testing frequency for governors;
2. unit-specific characteristics and governor settings; and
3. unit-specific performance information for a recent, single event.

NERC sent the survey instrument and instructions to 799 GOs and 748 GOPs in North America. Of the 794 GOs that acknowledged receipt of the survey, 749 developed and provided a response. Of the 743 GOPs that acknowledged receipt of the survey, 721 developed and provided a response.

Administrative Findings

NERC staff first reviewed the information submitted by the GOs and GOPs. This initial review led to the following findings from the administration of the survey:

1. There is a wide variety of levels of understanding among GOs and GOPs of the role of turbine governors in maintaining frequency response, including confusion in terminology and a lack of understanding of governor control settings. This indicates a need for education on settings and performance of turbine governors and the governor's role in interconnection frequency response.

Recommendation – NERC should address improving the level of understanding of the role of turbine governors through seminars and webinars, with educational materials available to GOs and GOPs on an ongoing basis.

2. There was a significant amount of duplication of reporting. This was mostly due to dual submittals by entities that are registered both as GOs and as GOPs. NERC staff sought to eliminate as much duplication as possible. However, eliminating duplication was difficult when the entities that own and operate a generator differ, yet both submitted information on the same generator. Hence, there remains some duplication in this analysis.

Summary of the Survey Responses

Table 22 summarizes, by interconnection, the aggregate characteristics of the generators analyzed.

Table 22: Number of Generators as Reported

Interconnection	Total	With Governors	Without Governors
Eastern	4,372 (648.7 GW)	4,217 (630.2 GW)	152 (18.5 GW)
Western	1,560 (171.6 GW)	1,445 (162.9 GW)	114 (8.7 GW)
ERCOT	503 (95.6 GW)	446 (85.6 GW)	53 (9.0 GW)
Totals	6,435 (915.9 GW)	6,110 (878.7 GW)	319 (36.2 GW)

Figures 46–48 summarize the responses on turbine governors for three of the interconnections. Data for the Québec Interconnection is not summarized in this report. The GOs and GOPs reported that governors were operational for 95%, 97%, and 99% of the total number of generating units that were reported as having governors in the Eastern, Western, and Texas Interconnections, respectively.

Figure 46: Eastern Interconnection Generator Responses

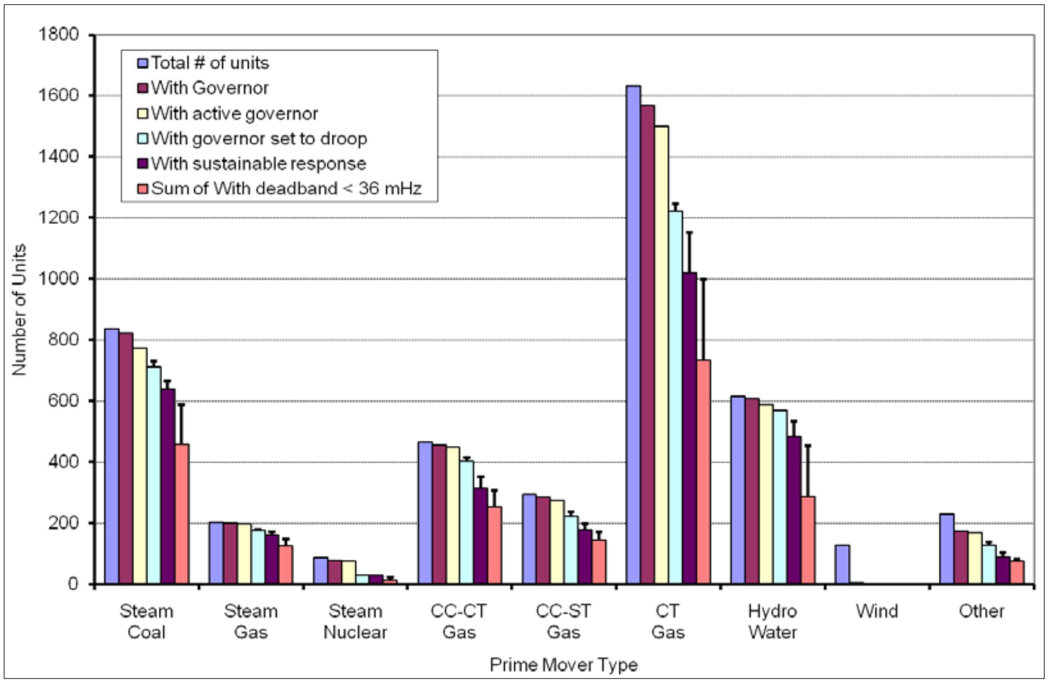


Figure 47: Western Interconnection Generator Responses

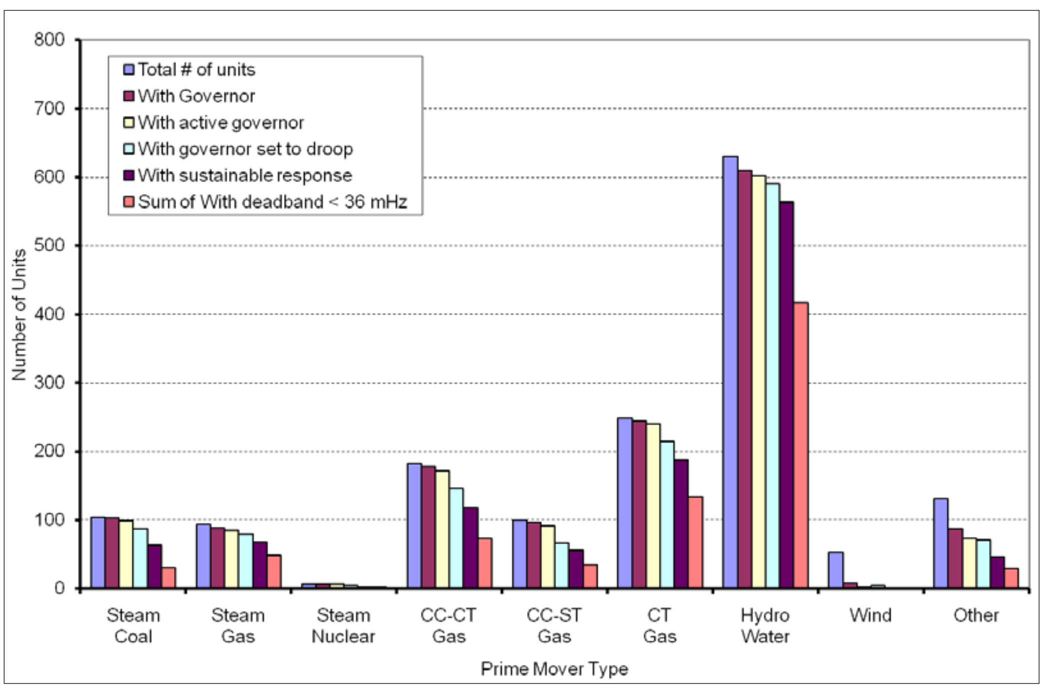
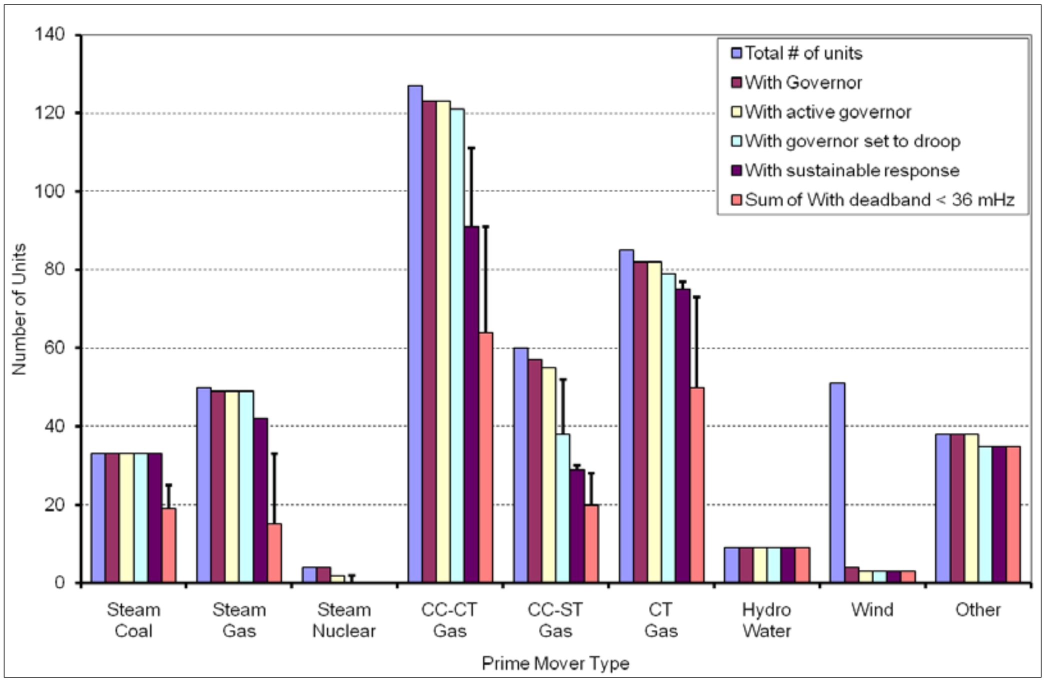


Figure 48: ERCOT Interconnection Generator Responses



Reported Deadband Settings

The deadband setting of a governor establishes a minimum frequency deviation that must be exceeded before the governor will act. Frequency deviations that are less than the setting will not cause the governor to act. Of the information provided by the GOs and GOPs on governor deadbands, 51%, 63%, and 79% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable. Figure 49 summarizes the usability of the deadband data submitted in the survey.

Figure 49: Usability of Information Provided on Governor Deadbands

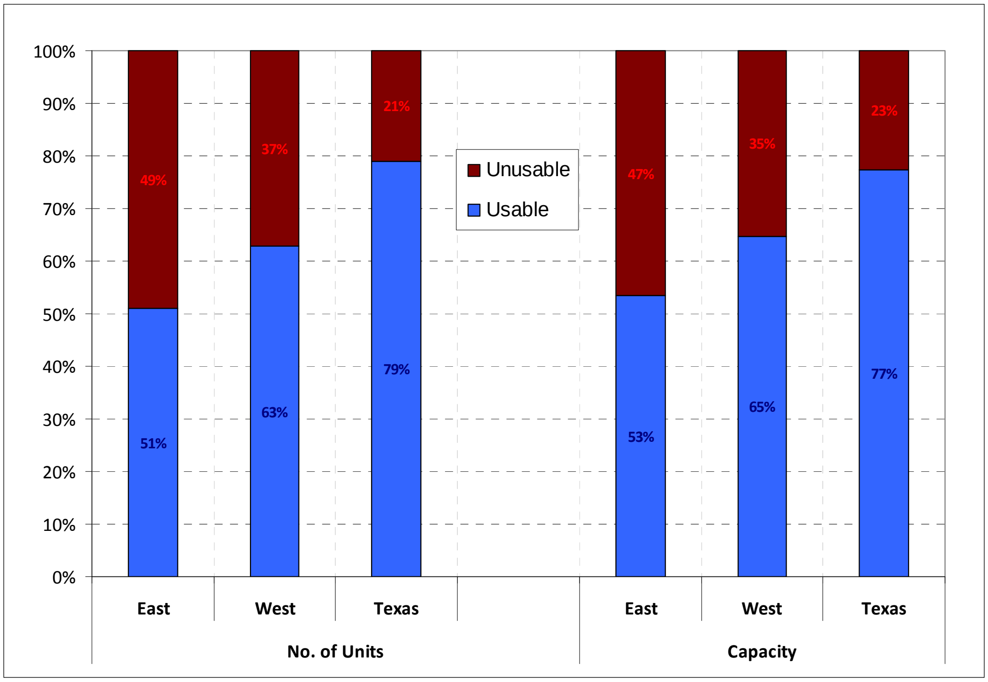


Figure 50 summarizes the range of deadband settings reported by generating unit size for all three interconnections. The simple average, or mean, of the frequency response values calculated is indicated by the orange dot. A horizontal line inside the green box indicates the median of these values. The upper and lower boundaries of the box are the inter-quartile range, which is the range that contains half the calculated frequency response values. Finally, the end points of the upper and lower vertical lines indicate the lowest and highest calculated frequency response values, respectively.

The use of these descriptive statistics provides additional information on the distribution of values. For example, if the average is lower than the median, it means that the distribution has a small number of low values compared to the main body of values. Similarly, the height of the inter-quartile range (the top and bottom of the box) provides a measure of how widely the values are distributed. The location of the median within the box indicates whether values are evenly distributed on either side of the median (when the median is close to the center of the box) or whether values are disproportionately on one or the other side of the median (when the median is closer to the top or the bottom of the box).

Figure 50: Reported Governor Deadband Settings

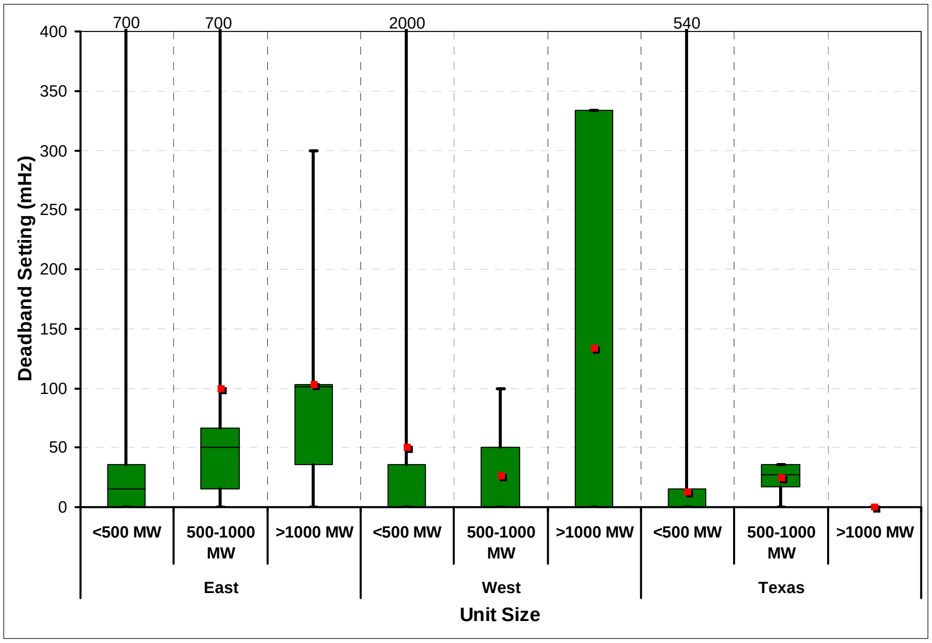


Figure 50 indicates:

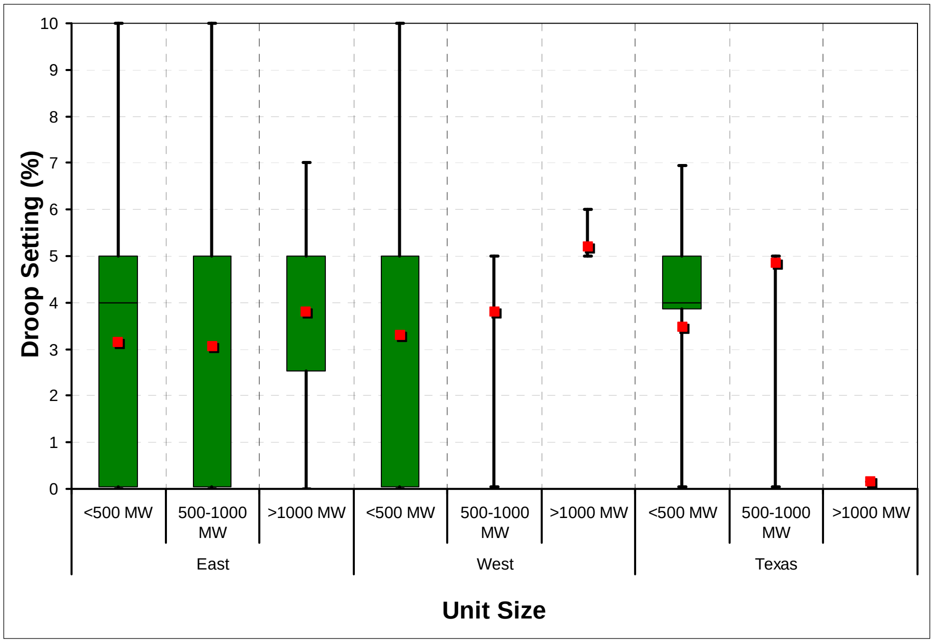
- Eastern Interconnection – Half of the deadband settings are between 0 and 100 mHz, with the smallest generating units having the lowest settings, followed by the mid-size, and then the largest units. The figure also indicates that there are a number of units in all size ranges with very high deadband settings (> 200 mHz).
- Western Interconnection – Half of the deadband settings are between 0 and 50 mHz for the smallest and mid-size generating units. However, the range is considerably broader for the largest units, with half of the settings lying between 0 and more than 300 mHz. The very large deadbands on units greater than 1,000 MW are attributable to the nuclear units.
- Texas Interconnection – The deadband settings are generally less than 50 mHz. There appears to be at least one very high deadband setting for a small generating unit.

Reported Droop Settings

Governor droop expresses the effect of changes in generating unit speed in terms of changes in power output as a function of the amount of frequency deviation from the reference frequency. Of the information provided by the GOs and GOPs on governor droop settings, 89%, 94%, and 87% of the number of units in the Eastern, Western, and Texas Interconnections, respectively, was usable.

Figure 51 summarizes the range of governor droop settings for the interconnections. Generally, the droop settings were in the range of expected values.

Figure 51: Range of Governor Droop Settings by Generating Unit Size



Governor Status and Operational Parameters

A number of the survey questions addressed the operational status and parameters of the governor fleet. As shown in Figure 52, the vast majority of the GOs and GOPs reported that their governors are operational.

Figure 53 shows that the governors also were reported to be able to sustain primary frequency response for longer than 1 minute if the frequency remains outside of its deadband. However, as shown in Figure 54, roughly half of the governors are expected to be overridden or limited by plant-level control schemes. This factor heavily influences the sustainability of primary frequency response, contributing to the withdrawal symptom often observed in the Eastern Interconnection, especially during light load periods.

Figure 52: Operational Status of Governors

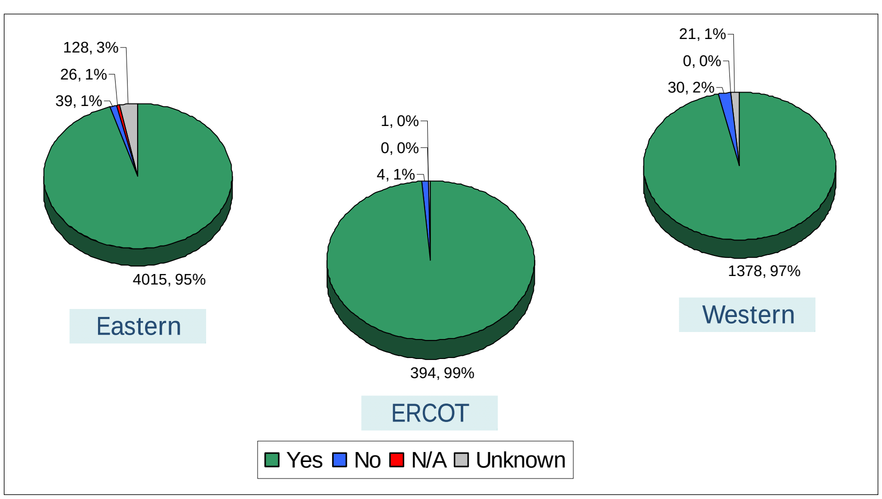


Figure 53: Response Sustainable for More Than 1 Minute if Outside Deadband

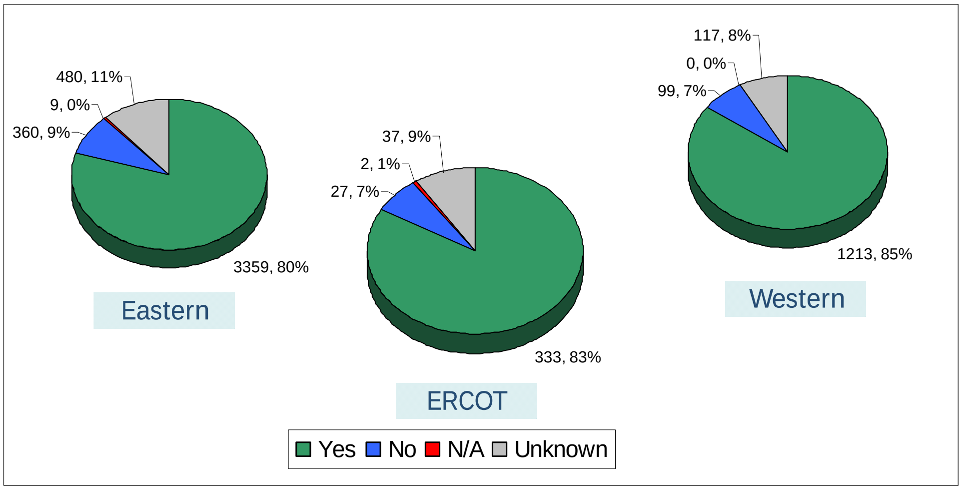
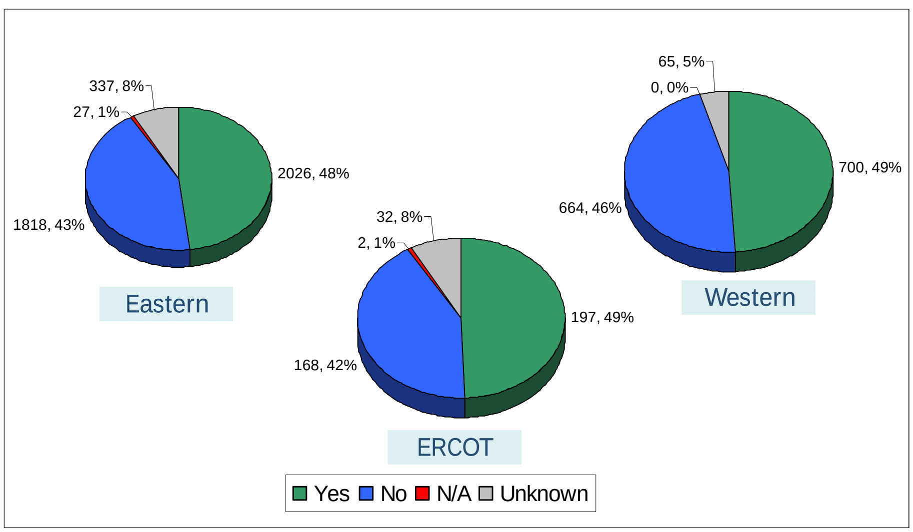


Figure 54: Unit-Level or Plant-Level Control Schemes that Override or Limit Governor Performance



Response to Selected Frequency Events

The GOs and GOPs were asked to provide information on the performance of turbine governors during a selected event in each interconnection. Table 23 lists the date and time of the events selected for the Eastern, Western, and Texas Interconnections (data was not requested from the Québec Interconnection).

Table 23: Selected Events for Provision of Generator Governor Performance Information		
Interconnection	Basis	Frequency
Eastern	8/16/2010 1:06:15 CST	1,200 MW
Western	8/12/2010 14:44:03 CST	1,260 MW
ERCOT	8/20/2010 14:25:29 CST	1,320 MW

Of the interconnections' total generating capacity, 64%, 58%, and 75% of the units were on-line at the time of the event for the Eastern, Western, and Texas Interconnections, respectively.

Figure 55: Governor Response by Total Generating Capacity On-Line

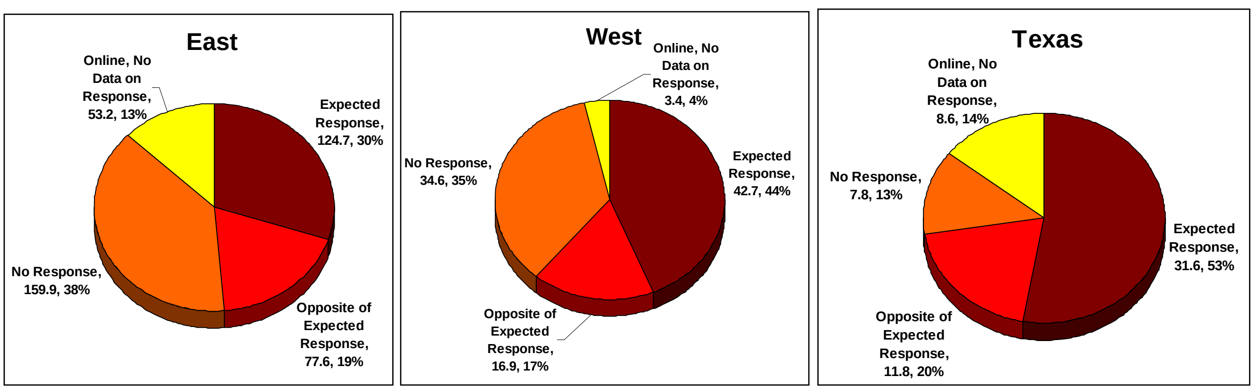


Figure 55 shows:

- Of the total generating capacity on-line, 30%, 44%, and 53% reported responding in the expected direction of response (i.e., to correct the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.
- Some generation reported no response to the frequency deviations (38%, 35%, and 13% for the Eastern, Western, and Texas Interconnections, respectively).
- Notably, 19%, 17%, and 20% were reported as responding in the opposite direction of the expected response (i.e., not in opposition to the change in frequency) for the Eastern, Western, and Texas Interconnections, respectively.

The values reported for the Eastern Interconnection for capacity providing expected response are in keeping with those calculated from the generic governor simulation of the frequency response to the August 4, 2007 Eastern Interconnection Frequency Disturbance. Those simulations showed that 30% of the capacity on-line responded, and 20% of the capacity on-line withdrew primary support, leaving only 10% of the capacity on-line providing sustained primary frequency response.

Figure 56 shows that for the Eastern Interconnection, total response in the expected direction was 973 MW, while response in the direction opposite expectations was -361 MW, for a total net response of 613 MW. Steam coal and combined-cycle gas turbine units, accounting for 327 MW and 244 MW of the net response, respectively, made the largest contributions. These contributions were made by steam coal and combine-cycle with a total on-line generating capacity of about 180 GW steam coal and about 60 GW combined-cycle gas turbine units, of which about 80 GW and about 10 GW of capacity provided response in the expected direction, respectively.

Figure 56: Eastern Interconnection Generator Governor Performance

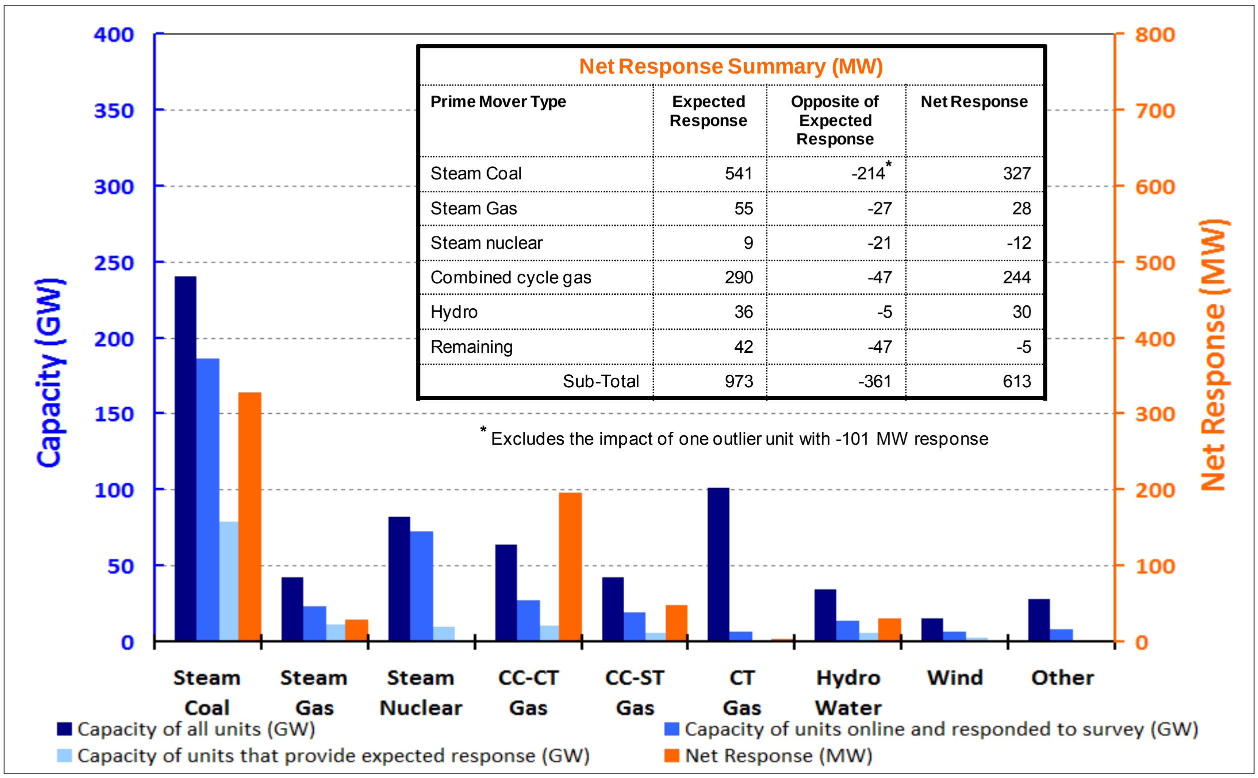
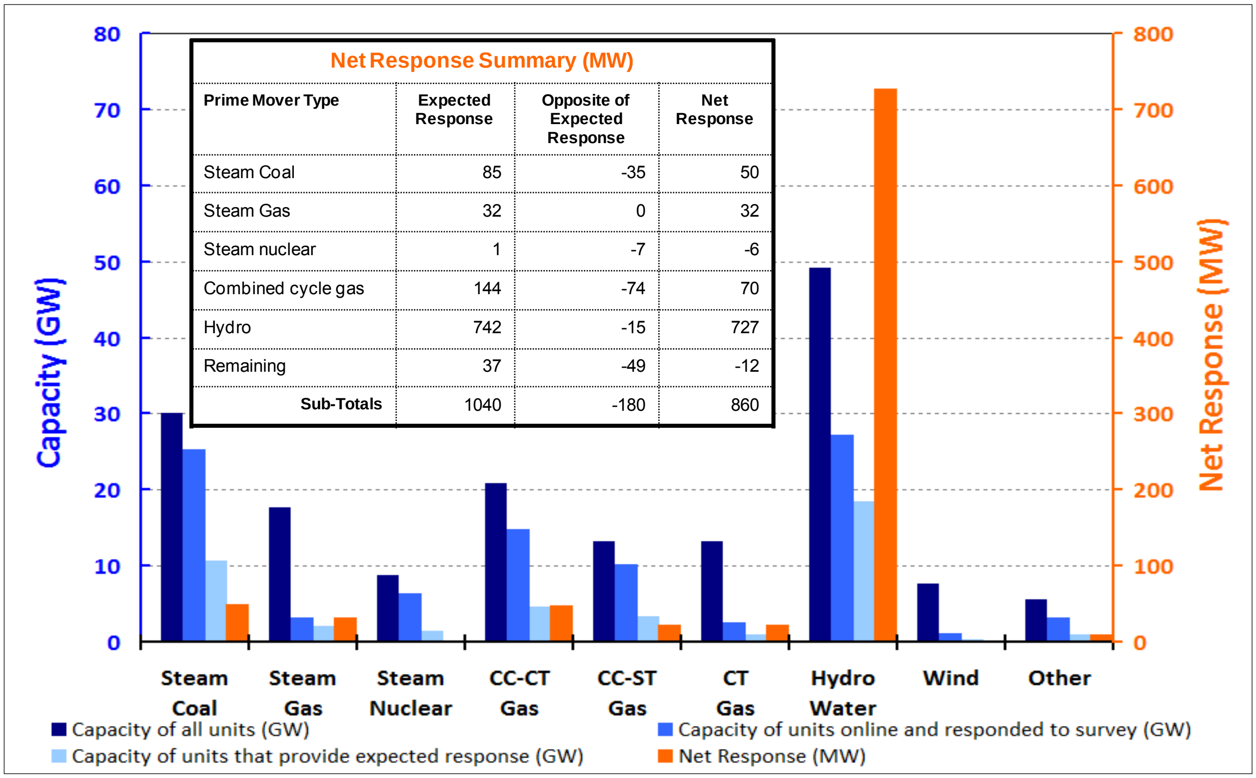


Figure 57 shows that for the Western Interconnection, total response in the expected direction was 1040 MW, while response in the direction opposite expectations was -180 MW, for a total net response of 860 MW. Hydro units, accounting for 727 MW of the net response, made the largest contribution. Hydro units made this contribution with a total on-line generating capacity of about 50 GW, of which about 19 GW of capacity provided response in the expected direction.

Figure 57: Western Interconnection Generator Governor Performance

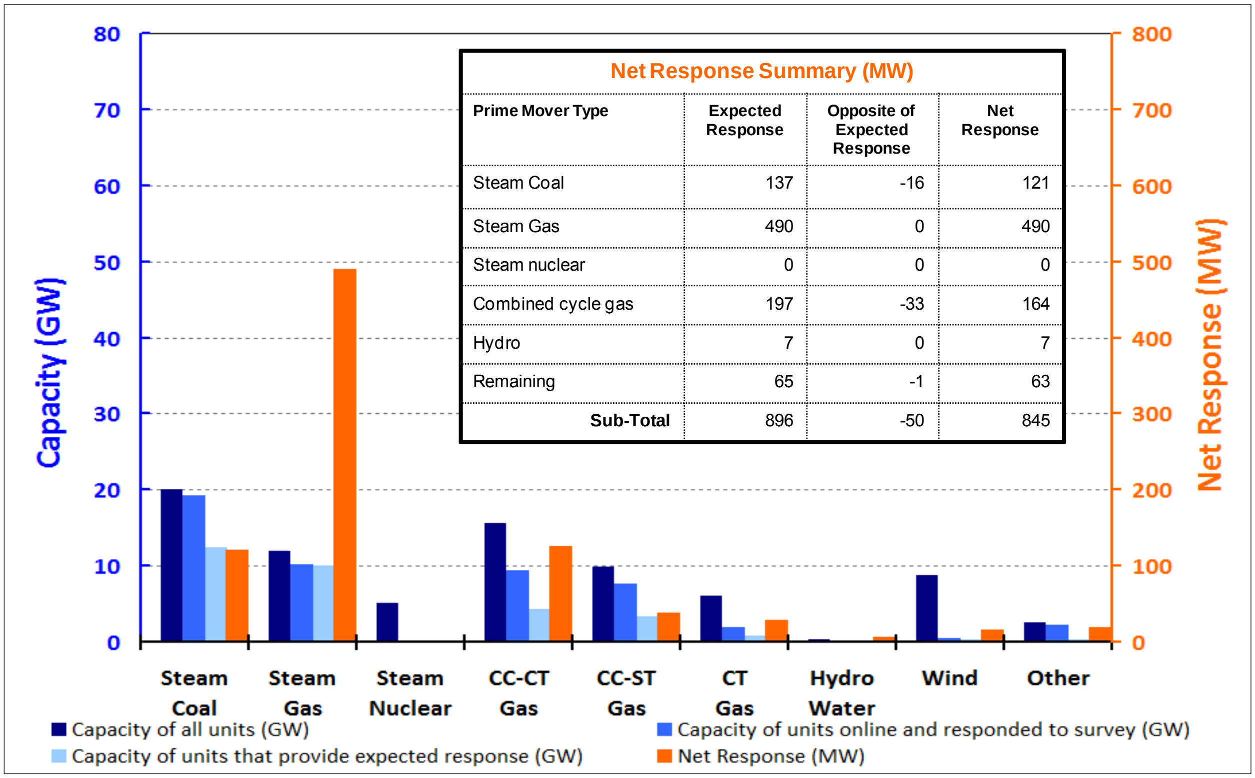


Net Response Summary (MW)

Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	85	-35	50
Steam Gas	32	0	32
Steam nuclear	1	-7	-6
Combined cycle gas	144	-74	70
Hydro	742	-15	727
Remaining	37	-49	-12
Sub-Totals	1040	-180	860

Figure 58 shows that for the ERCOT Interconnection, total response in the expected direction was 896 MW, while response in the direction opposite expectations was -50 MW, for a total net response of 845 MW. Steam gas units, accounting for 490 MW of the net response, made the largest contribution. Steam gas units made this contribution with a total on-line generating capacity of about 11 GW, of which ~10 GW of capacity provided response in the expected direction.

Figure 58: ERCOT Interconnection Generator Governor Performance



Net Response Summary (MW)

Prime Mover Type	Expected Response	Opposite of Expected Response	Net Response
Steam Coal	137	-16	121
Steam Gas	490	0	490
Steam nuclear	0	0	0
Combined cycle gas	197	-33	164
Hydro	7	0	7
Remaining	65	-1	63
Sub-Total	896	-50	845

Future Analysis Work Recommendations

Testing of Eastern Interconnection Maximum Allowable Frequency Deviations

The stability simulation testing of the Eastern Interconnection resource loss criteria used in the determination of the IFRO was limited to analysis using the generic governor stability case developed by the NERC Model Validation Working Group and the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) in December 2011 (based on the August 4, 2007 Eastern Interconnection Frequency Disturbance). Simulations using that stability simulation indicated a maximum sustainable generation loss of about 8,500 MW for the Eastern Interconnection. However, that simulation case was not for the light load conditions where system inertia and load response would be expected to be lower than in the generic case.

Recommendation – Dynamic simulation testing of the Western and ERCOT Resource Contingency Protection Criteria should be conducted as soon as possible.

Recommendation – When ERAG MMWG completes its review of turbine governor modeling, a new light-load case should be developed, and the resource loss criterion for the Eastern Interconnection's IFRO should be re-simulated.

Eastern Interconnection Inter-area Oscillations – Potential for Large Resource Losses

During the spring of 2012, a number of inter-area oscillations were observed between the upper Midwest and the New England/New Brunswick areas in the 0.25 Hz family. During one such event, a large generation outage in Georgia instigated that oscillation mode and was interpreted by the FNet frequency monitoring and event detection program as an 1,800 MW resource loss in the upper Midwest. Immediately, the FNet Oscillation Monitoring system detected the 0.025 Hz family oscillations between the upper Midwest and New England/New Brunswick. Investigation into the event showed that it occurred while the Dorsey – Forbes 500 kV transmission line was out of service for maintenance. During that line outage, the transfers on the Dorsey DC line from Northern Manitoba were significantly curtailed, and the oscillation of the Dorsey DC terminal capabilities for damping the 0.025 Hz oscillations were greatly reduced. This made the system more susceptible to such oscillations. In all instances, the energy magnitude under the oscillations was small, well-damped, and of little danger to the reliability of the Eastern Interconnection.

However, the instigation of those oscillations by a generator trip in Georgia seemed unlikely until reviewed in light of the inter-area oscillations detected following the South Florida disturbance of February 26, 2008. During that disturbance, a family of 0.22 Hz oscillations was detected between the Southeast and the upper Midwest. In both cases, the same generation in the upper Midwest has a strong participation in both mode shapes, and since both oscillation modes are close in frequency, the 0.25 Hz family was easily perturbed by an instance of the 0.22 Hz mode oscillations caused by the Georgia generator tripping.

Recommendation – Eastern Interconnection inter-area oscillatory behavior should be further investigated by NERC, including during the testing of large resource loss analysis for IFRO validation.

Appendices Table of Contents

Appendix A – Contributors

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NERC Frequency Response Standard Drafting Team

NERC Frequency Working Group

NERC Resources Subcommittee

NERC System Analysis and Modeling Subcommittee (formerly the Transmission Issues Subcommittee)

[1] Participation made possible through funding provided by the U.S. Department of Energy Office of Electricity and Energy Reliability, coordinated through the Lawrence Berkeley National Laboratory.

Appendix B – Abbreviations

ACE	Area Control Error
ADF	Adjusted Delta Frequency
AGC	Automatic Generator Control
ALR	Acceptable Level of Reliability
ARLPC	Adjusted resource loss protection criteria adjusted for the credit for load resources
BA	Balancing Authority
BAA	Balancing Authority Area
CERTS	Consortium for Electric Reliability Technology Solutions
CPS	Control Performance Standard
CB_R	Ratio of the Point C to Value B to adjust the allowable delta frequency to account for that difference.
CC_{ADJ}	Adjustment to Point C for the differences between 1-second and sub-second measurements
COI	California-Oregon Interface (ac)
D	Load damping factor
dc	Direct current
DCS	Disturbance Control Standard
DF_{Base}	Base delta frequency
DF_{CC}	Delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events
EMS	Energy Management System
EPG	Electric Power Group
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
F_{Start}	Starting Frequency
FERC	The U.S. Federal Energy Regulatory Commission
FDR	Frequency Disturbance Recorder
FMA	Frequency Monitoring and Analysis tool
FNet	Frequency Monitoring Network (University of Tennessee, Knoxville, and Virginia Tech)
FRC	Frequency Response Characteristic
FRCC	Florida Reliability Coordinating Council
FRM	Frequency Response Measure
FRO	Frequency Response Obligation (FRO_{BA})
FRRSDT	Frequency Response Standard Drafting Team

FR	Frequency Response
FRS	Frequency Response Standard
FRSG	Frequency Response Sharing Group
FWG	Frequency Working Group
GOs	Generator Owners
GOPs	Generator Operators
GVD	Governor Valve Demand
GW	gigawatts (thousands of megawatts)
H	Inertial constant (of the interconnection)
Hz	hertz (cycles per second)
IFRO	Interconnection Frequency Response Obligation (FRO_{Int})
LaaR	Load Acting as a Resource
LBNL	Ernest Orlando Lawrence Berkeley National Laboratory
mHz	millihertz
MMWG	Multi-Regional Modeling Working Group
MVA	megavoltampere
MW	megawatts
N-1	Loss of one system element
N-2	Loss of two system elements
NI_A	Net Interchange Actual
NI_S	Net Interchange Scheduled
PAS	Performance Analysis Subcommittee
PDCI	Pacific Direct Current Intertie
PDCWG	Performance Disturbance and Compliance Working Group (ERCOT)
PMU	Phasor Measurement Unit
PV	Photovoltaic
RA	Resource Adequacy Tool
RARF	ERCOT Resource Asset Registration Form
RAS	Remedial Action Scheme (also known as a Special Protection Scheme – SPS)
RLPC	Resource Loss Protection Criteria
RPM	Revolutions per Minute
RC	Resources Subcommittee
SAMS	System Analysis and Modeling Subcommittee (formerly TIS)
SCADA	System Control and Data Acquisition
SEFRD	Single Event Frequency Response Data
SEFRD	Single Event Frequency Response Data
TIS	Transmission Issues Subcommittee (now SAMS)
TRE	Texas Regional Entity

UFLS	Under-Frequency Load Shedding

Appendix C – Definitions and Terminology

Definitions used in Standard BAL-003-1

Frequency Response Measure (FRM)

The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.

Frequency Response Obligation (FRO)

The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.

Frequency Bias Setting

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's inverse Frequency Response contribution to the interconnection, and discourage response withdrawal through secondary control systems.

Frequency Response Sharing Group (FRSG)

Groups, whose members consist of two or more Balancing Authorities, that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.

Area Control Error (ACE)*: The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Arrested Frequency – Value C – Point C – Frequency Nadir: The point of maximum frequency excursion in the first swing of the frequency excursion between time zero (Point A) and time zero plus 20 seconds.

Arresting Period: The period of time from time zero (Point A) to the time of Point C.

Arresting Period Frequency Response: A combination of load damping and the initial Primary Control Response acting together to limit the duration and magnitude of frequency change during the Arresting Period.

Automatic Generation Control (AGC)*: 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.

Balancing Authority (BA)*: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Beta: The factor by which the frequency deviation is multiplied by in the ACE equation to adjust the ACE to protect a BA's Frequency Response.

Contingency Protection Criteria of an interconnection: The selected capacity contingency that an interconnection must withstand at all times without the activation of the first tier of UFLS.

Contingency Reserve*: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

Frequency [i]: The rate at which a repeating waveform repeats itself. Frequency is measured in cycles per second or in hertz (Hz). The symbol is "F."

Frequency Bias Setting: The term of the ACE equation that is multiplied by frequency deviation portion. This is a corrective term to offset the tie-line flow error caused by generation/load responding to a frequency deviation.

Frequency Deviation*: A change in interconnection frequency.

Frequency Response*: (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Frequency Responsive Reserve (a.k.a., dynamic headroom): The capacity of Governor Response and/or Frequency-Responsive Demand Response that will be deployed for any frequency excursion.

Frequency-Responsive Demand Response: Voluntary load shedding that complements governor response. This load reduction is typically triggered by relays that are activated by frequency.

Frequency Sensitive Load: Customer loads that vary directly with changes in frequency or would trip as a result of frequency deviations.

Governor response[§]: The control response of turbine-governors to sensing a change in speed of the turbine as frequency increases or declines, causing an adjustment to the energy input of the turbine's prime mover.

Headroom: The difference between the current operating point of a generator and its maximum operating capability.

Inertia[i]: The property of an object that resists changes to the motion of an object. For example, the inertia of a rotating object resists changes to the object's speed of rotation. The inertia of a rotating object is a function of its mass, diameter, and speed of rotation.

Load damping[¥]: The damping effect of the load to a change in frequency due to the physical aspects of the load such as the inertia of motors and the physical load to which they are connected.

Load following[i]: Commitment of energy based resources (generation or energy schedule) to match the forecast load level for a given period. This is a form of course control for moment-by-moment resource/load matching.

Non-spinning reserve*: 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

Off-line Reserve[§]: The off-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

On-line Reserve[§]: The on-line capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. This can consist of spinning reserve and interruptible load that can act as a resource.

Operating Reserve*: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves.

Other On-line Reserves[§]: On-line Resources that can increase their output or connected loads that can decrease their consumption (curtailable loads) in time frames outside the continuum of regulating or spinning reserve (i.e. on four hours' notice).

Other Off-line Reserves[§]: Resources that can be brought to bear outside the continuum of non-spinning reserve (i.e., on four hours' notice).

Plant secondary control[@]: Secondary control refers to controls affected through commands to a turbine controller issued by external entities not necessarily working in concert with frequency management objectives. It is common for a modern power plant to have several distinct modes of secondary control implemented within the plant and to be able to accept secondary control inputs from sources external to the plant.

Primary Control Response Withdrawal: The withdrawal of previously delivered Primary Control Response, through plant secondary controls.

Primary Frequency Control Response: The power delivered to the interconnection in response to a frequency deviation through generator governor response, load response (typically from motors), demand response (designed to arrest frequency excursions), and other devices that provide an immediate response to frequency based on local (device-level) control systems, without human or remote intervention.

Primary Frequency Control Reserves: Frequency-responsive reserves that respond nearly instantaneously (starting in less than 1 second) to oppose any changes in power system frequency.

Quick Start Reserve: A form of non-spinning reserve that can be put on-line and the capacity that can be deployed in ten minutes.

Recovery Period: The period of time from when Secondary Control Response are deployed (typically about zero plus 53 seconds) to the time of the return of frequency to within pre-established ranges of reliable continuous operation.

Regulation[¥]: Controllable resources necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interchange and interconnection scheduled frequency. Regulation is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes actual net interchange.

Regulating reserve*: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide a normal regulating margin.

Settling frequency[¥, #]: Refers to the third key event during a disturbance when the frequency stabilizes following a frequency excursion. Point B represents the interconnected system frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent control area takes corrective AGC action.

Secondary Control Response: The power delivered by a Balancing Authority or Reserve Sharing Group in response to a frequency deviation through Secondary Control actions, such as manual or automated dispatch from a centralized control system. Secondary control actions are intended to restore Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency, or maintain Scheduled Frequency.

Secondary Frequency Control: Actions provided by an individual BA or its Reserve Sharing Group intended to restore Primary Control Response and restore frequency from the Arrested Frequency back to Scheduled Frequency, or to maintain Scheduled Frequency deployed in the "minutes" time frame. Secondary Control comes from either manual or automated dispatch from a centralized control system. Secondary Control also includes initial reserve deployment for disturbances and maintains the minute-to-minute balance throughout the day and is used to restore frequency to normal following a disturbance and is provided by both spinning and non-spinning reserves.

Secondary Frequency Control Reserves: Frequency-responsive reserves that respond over slightly longer time frames (starting in 20-30 seconds). Following the sudden loss of generation, they assist in restoring frequency to the scheduled value after Primary Frequency Control Reserves have been deployed. They also safeguard Primary Frequency Control Reserves (so that primary reserves remain available to respond to these sudden events) by controlling frequency in response to slower imbalances that arise between electricity demand and generation such as the normal rise and fall of system load over the course of a day.

Spinning reserve*: Unloaded generation that is synchronized and ready to serve additional demand.

Tertiary frequency control[§]: Encompasses actions taken to get resources in place to handle current and future changes in load or contingencies. Reserve deployment and Reserve restoration following a disturbance is a common type of Tertiary frequency control.

Under-frequency load shedding[i]: The tripping of customer load based on magnitudes of system frequency. For example, a utility may dump 5% of their connected load if frequency falls below 59.3 Hz, dump an additional 10% if frequency falls below 58.9 Hz, and dump a final 10% if frequency falls below 58.5 Hz. These three steps of load shedding would form this utility's UFLS plan. The purpose of UFLS is a final effort (safety net) to arrest a frequency decline.

Sources:

* NERC Glossary of Terms Used in Reliability Standards, http://www.nerc.com/files/Glossary_of_Terms.pdf

[¥] NERC Reference Document Understand and Calculating Frequency Response (June 19, 2008)

[§] NERC Balancing and Frequency Control (July 5, 2009)

[#] NERC Frequency Response Characteristic Survey Training Document, http://www.nerc.com/docs/standards/sar/opman_12-13Mar08_FrequencyResponseCharacteristicSurveyTrainingDocument.pdf (January 1, 1989)

[@] Undrill, J.M. 2010. *Power and Frequency Control as it Relates to Wind-Powered Generation*. LBNL-4143E. Berkeley: Lawrence Berkeley National Laboratory

[i] Definitions taken from the EPRI Power Systems Dynamics Tutorial. EPRI, Palo Alto, CA: 2009. 1016042

Appendix D – Interconnection Frequency Deviation Duration Plots

Figure D1: Summary of Eastern Interconnection Frequency 2007–2011

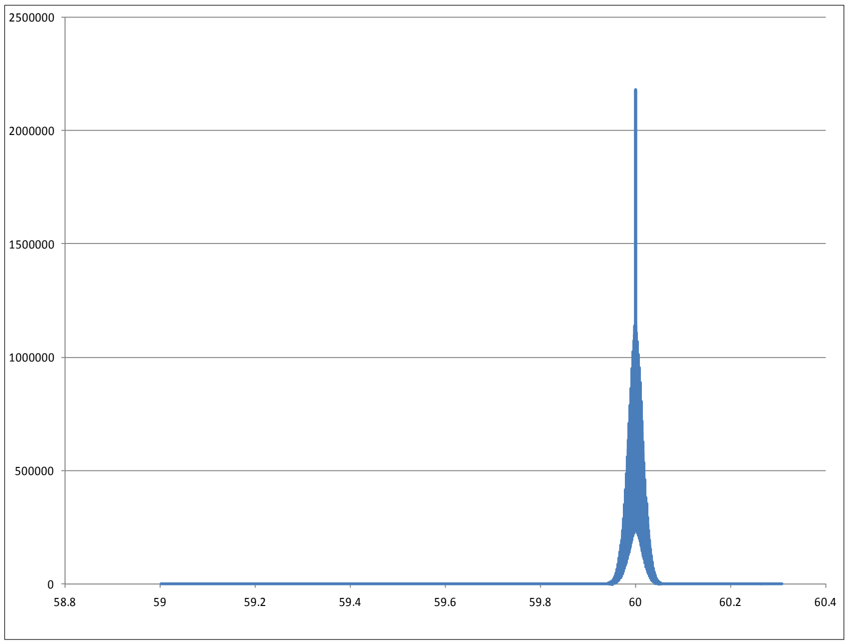


Figure D2: Eastern Interconnection 2007–2011 Frequency Histogram

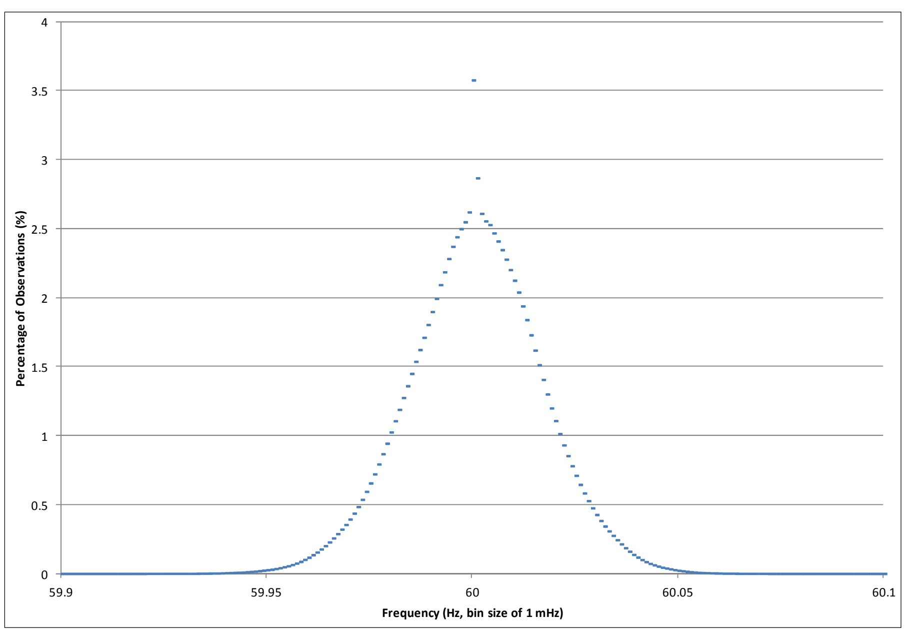


Figure D3: Eastern Interconnection Frequency 2007–2011 Cumulative Distribution

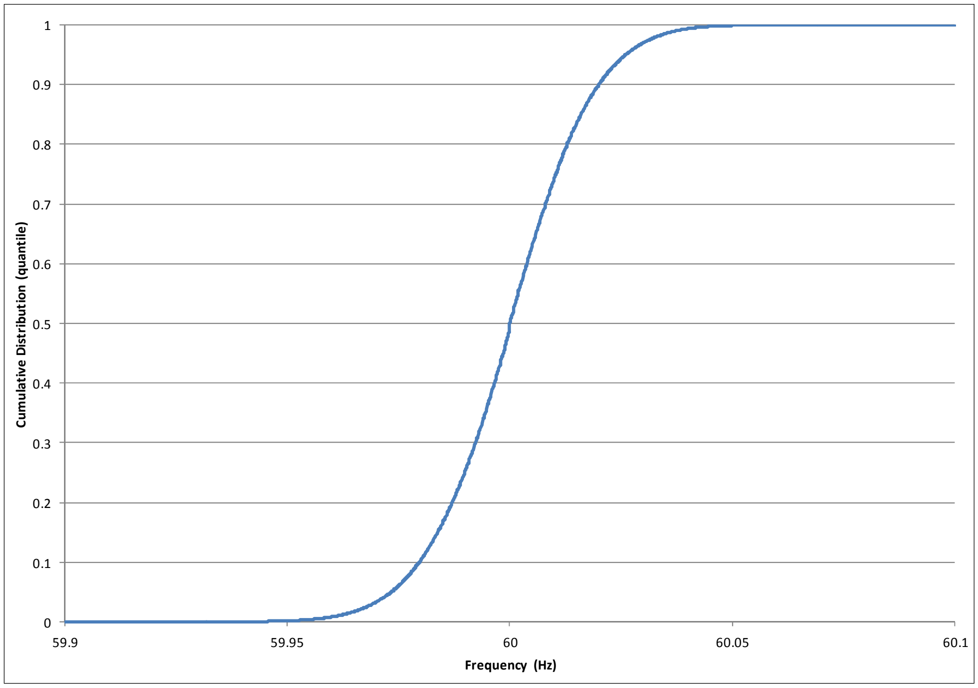


Figure D4: Summary of Western Interconnection Frequency 2007–2011

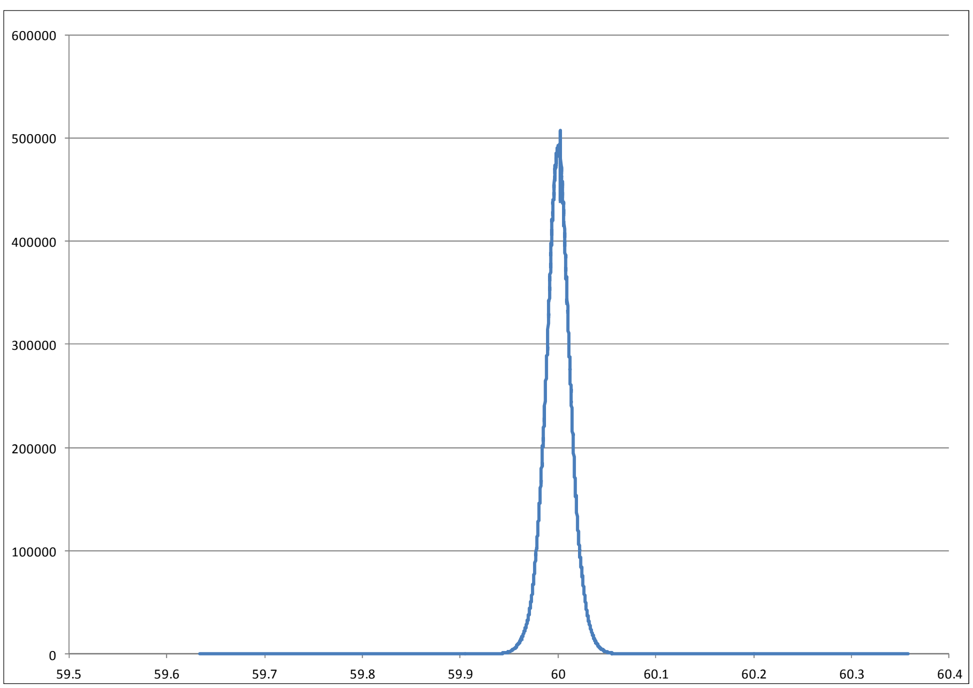


Figure D5: Western Interconnection 2007–2011 Frequency Histogram

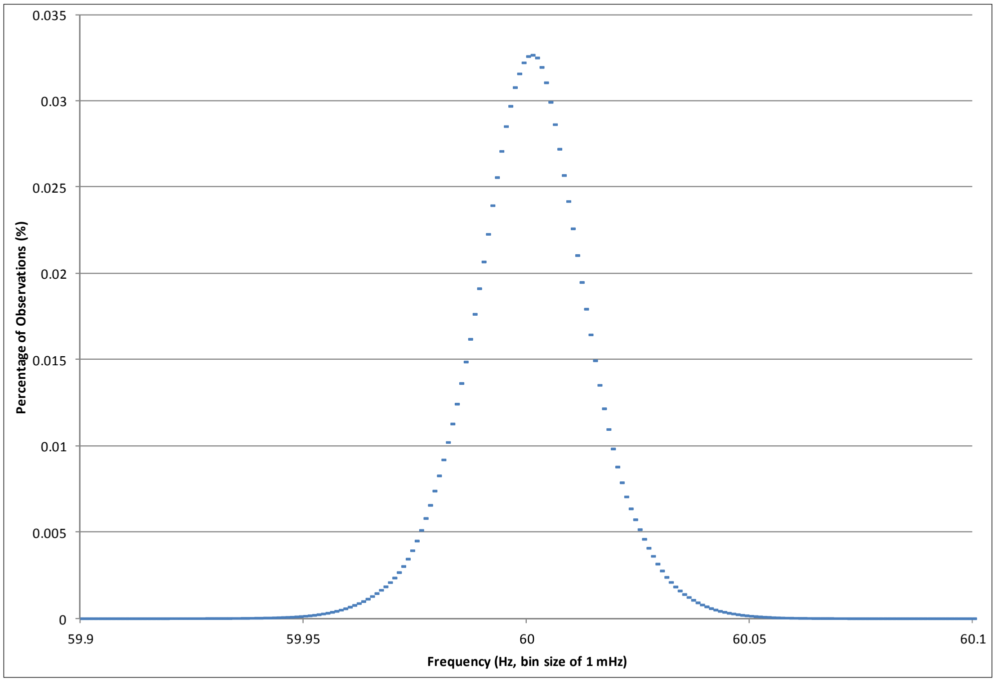


Figure D6: Western Interconnection Frequency 2007–2011 Cumulative Distribution

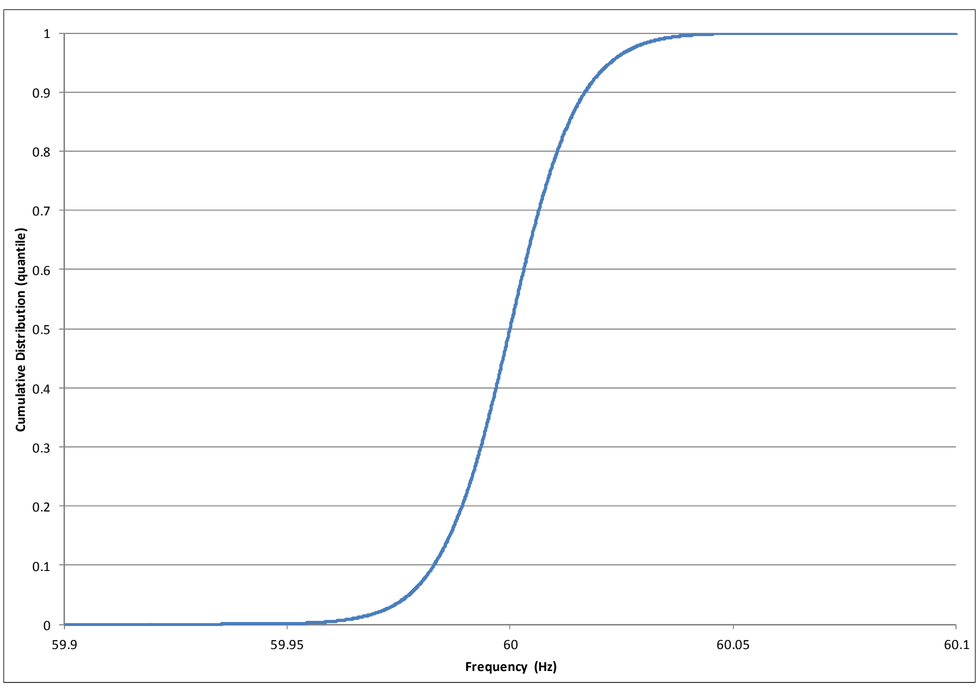


Figure D7: Summary of ERCOT Interconnection Frequency 2007–2011

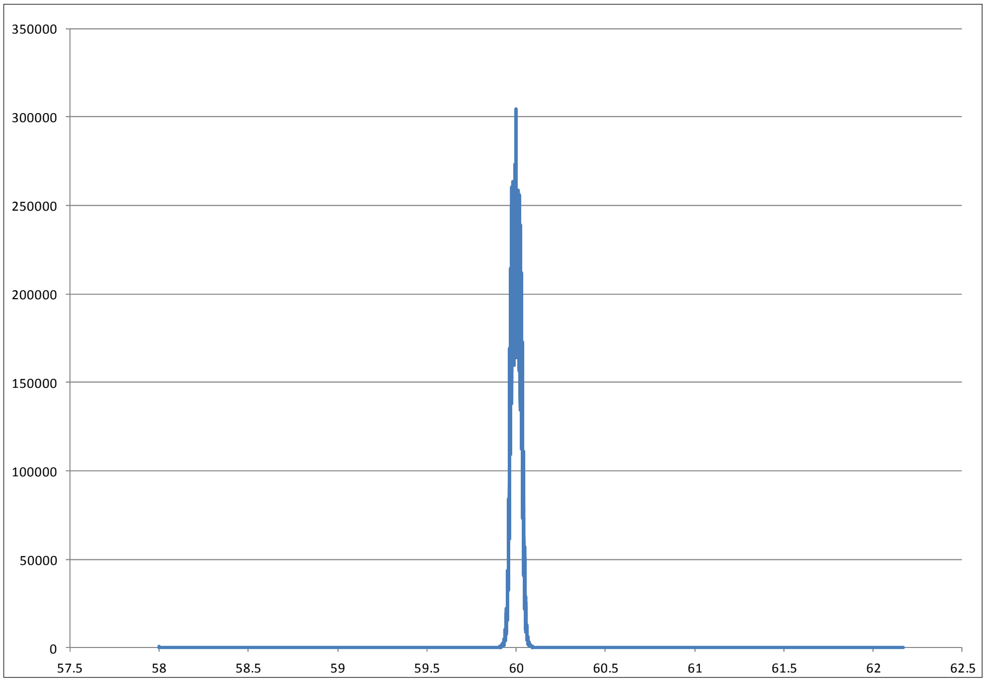


Figure D8: ERCOT Interconnection 2007–2011 Frequency Histogram

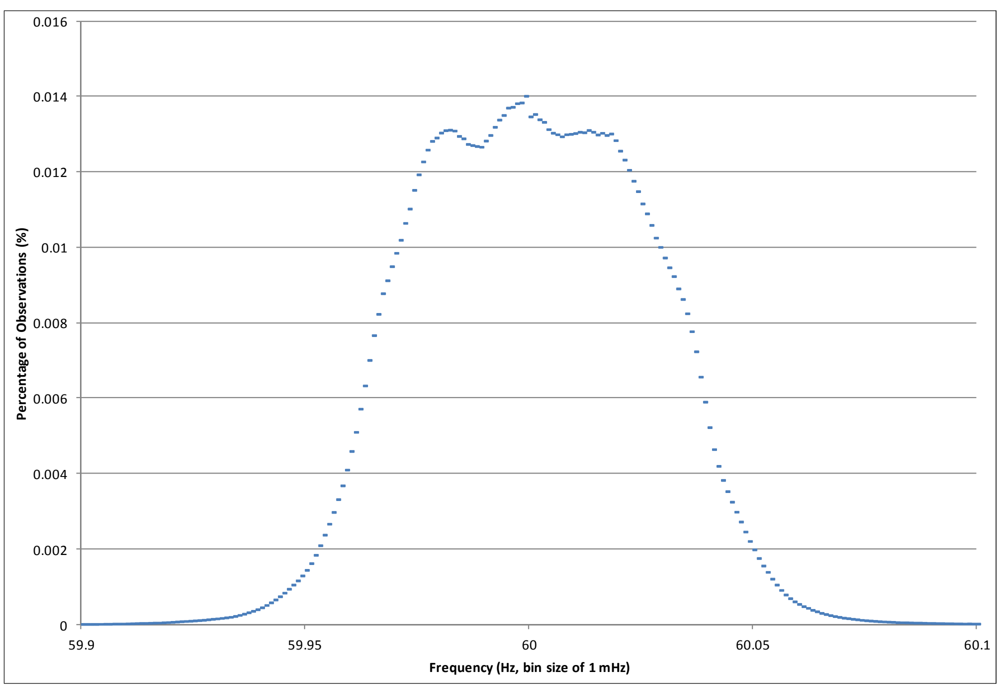


Figure D9: ERCOT Interconnection Frequency 2007–2011 Cumulative Distribution

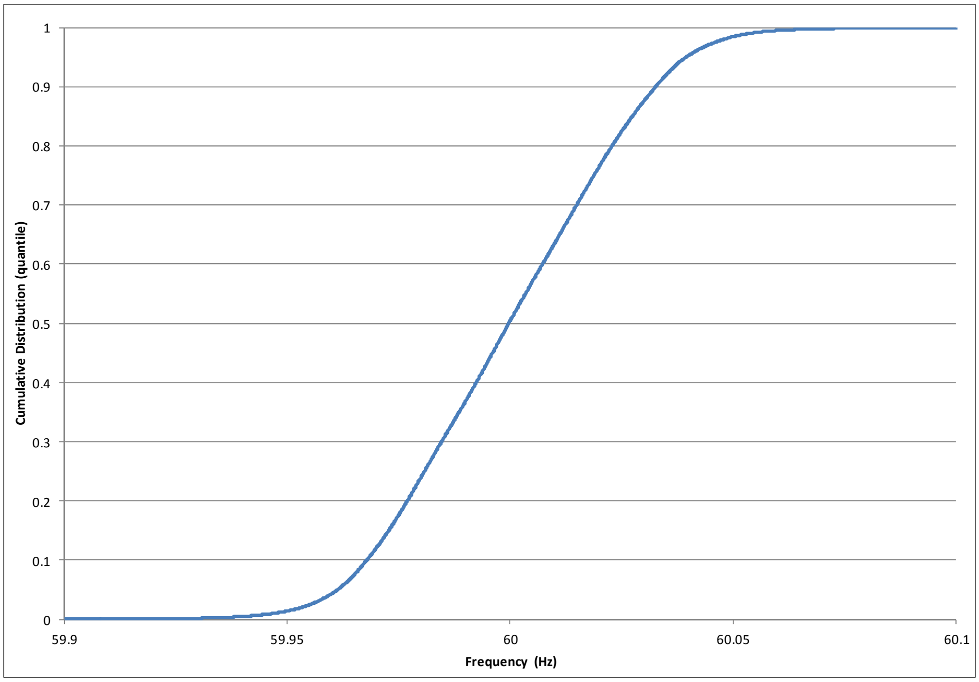


Figure D10: Summary of Québec Interconnection Frequency 2010–2011

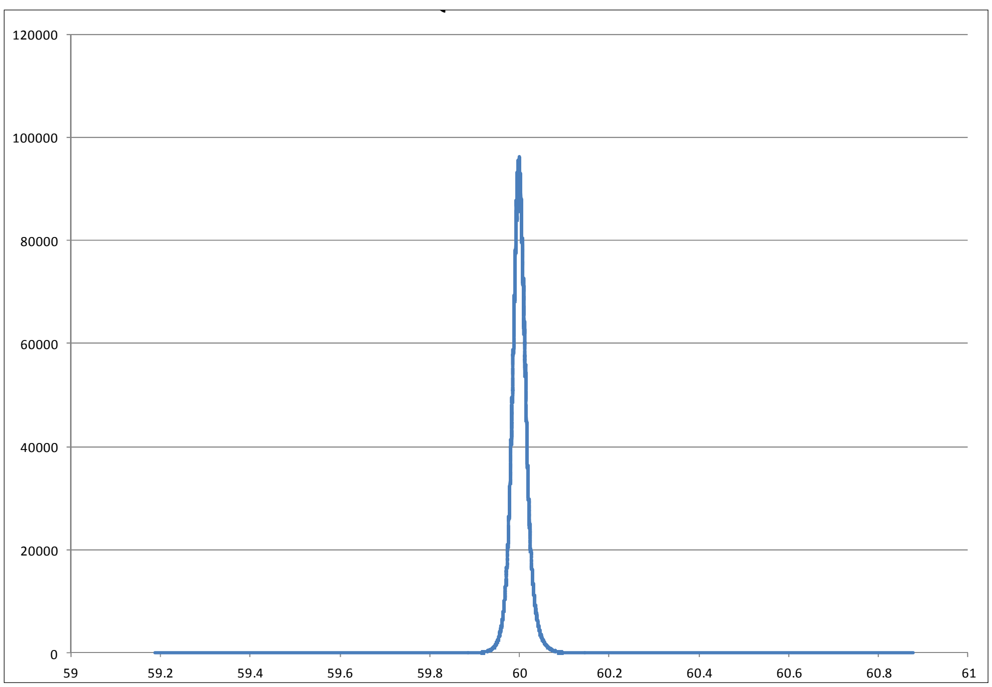


Figure D11: Québec Interconnection 2010–2011 Frequency Histogram

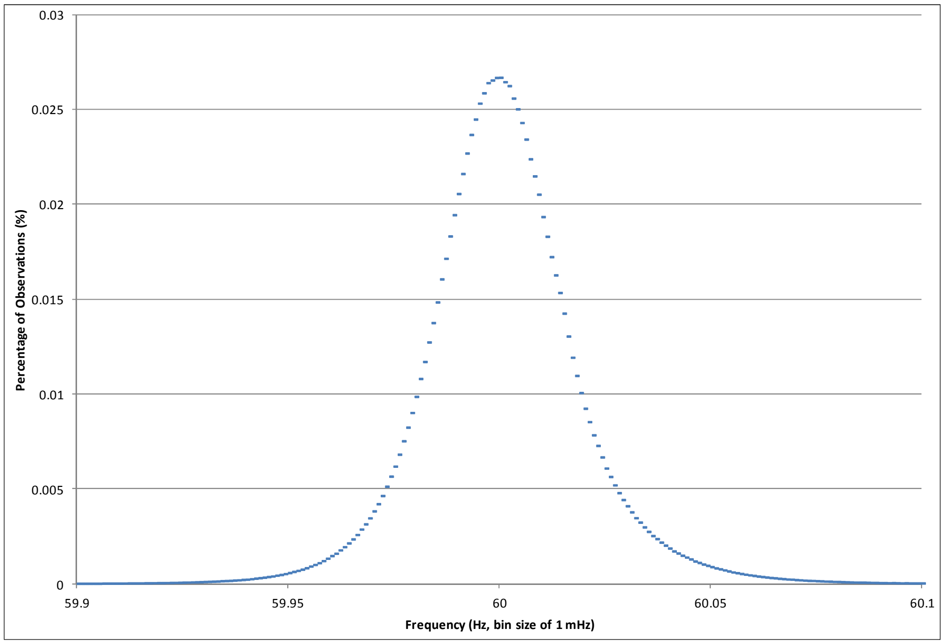
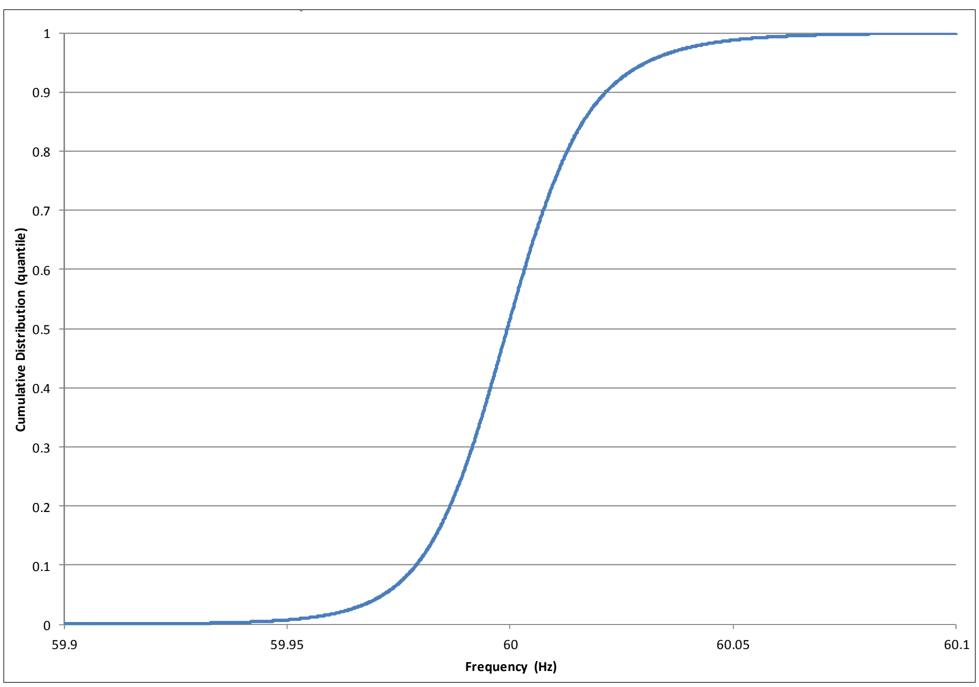


Figure D12: Québec Interconnection Frequency 2010–2011 Cumulative Distribution



Appendix E – ALR1-12 Metric Event Selection Process

1. CERTS-EPG produces a monthly spreadsheet for four interconnections (Eastern Interconnection or EI, Western or WI, ERCOT Interconnection or TI, and Québec). The spreadsheet captures significant frequency events based on the Resources Subcommittee (RS) specified threshold. The Frequency Monitoring and Analysis tool (FMA) gathers and stores the raw data.
2. The spreadsheet is sent by CERTS-EPG to the Frequency Working Group (FWG) on the 15th of each month for the previous month's raw data.
3. The FNET application uses automatic e-mails to flag frequency deviations. Generation loss is estimated.
4. The actual generation loss for the FNET flagged frequency events is determined by the NERC Situation Awareness Coordinator from the Regional Entities and sent to the FWG.
5. The FWG members validate the data and add the actual generation loss values into the spreadsheet.
6. FWG sends the validated monthly sheet to the Resource Subcommittee (RS) and the Performance Analysis Subcommittee (PAS) on the 30th of each month for the previous month's raw data.
7. NERC staff will update the candidate event list on the NERC website that will be used to support the standard. The final official event list for a year will be identified as a subset of the posted candidate list.
8. PAS publishes the quarterly Frequency Response metric data on NERC's Reliability Indicators webpage. The initial trending will be based on annual median/mean and rolling 12 month values.

Background Information

The frequency delta thresholds recommended by RS for the Eastern, Western, ERCOT and Québec Interconnections are shown in Table E1.

Table E1: Frequency delta thresholds recommended by RS

Interconnections	Frequency Delta for events captured in (mHz)	Frequency Delta for Significant events that have a higher Delta	Time Window (Seconds)
Eastern	24	36	15
Western	40	70	15
ERCOT	45	90	15
Québec	140	200	15

The raw statistics for events in 2008, 2009, 2010 and the first half of 2011 are listed in Table E2 below. This was sent by CERTS-EPG to the FWG on August 31, 2011.

Table E2: Raw Statistics for frequency events from 2008 to July 2011

Interconnection	Eastern	Western	ERCOT	Québec
2008	195	102	26	No Data
2009	78	72	85	No Data
2010	132	85	122	No Data
2011 (until July)	70	37	61	159

The statistics for TI from 2008 to 2011 were validated and modified by the FWG. Table E3 shows the statistics for TI that were sent by the FWG to the RS on September 02, 2011.

Table E3: Validated Statistics for TI frequency events from 2008 to July 2011

Interconnections	TI
2008	8
2009	51
2010	67
2011 (until July)	40

The FWG Lead members who will validate the data and add the actual generation loss values into the spreadsheet for the four interconnections are listed in Table E4.

Table E4: Lead members for the four interconnections

Terry L. Bilke	Eastern Interconnection
Don E. Badley	Western Interconnection
Sydney L. Niemeyer	ERCOT Interconnection
Michael Potishnak	Québec Interconnection

In July 2011, CERTS-EPG produced the first of the monthly reports for the FWG. July 2011 has 22 frequency events and a summary is shown in Table E5.

Table E5: Summary of the 1st monthly report produced by CERTS-EPG for the FWG in July 2011

NERC INTERCONNECTION JULY, 2011 FREQUENCY EVENTS – SUMMARY DATA

Eastern Interconnection

Event Time: UTC (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Event Time: Local Time (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
07/02/2011 6:45:21	07/02/2011 2:45:21	Sat	EDT	0.004	60.004	59.956	-0.048	59.969	-0.035	6349		-975	EES				-2024
07/02/2011 14:57:18	07/02/2011 10:57:18	Sat	EDT	-0.003	59.997	59.967	-0.031	59.958	-0.039	6349		-496	TVA				-1600
07/16/2011 7:07:00	07/16/2011 3:07:00	Sat	EDT	-0.007	59.993	59.948	-0.045	59.952	-0.041	6349		-613	TVA				-1370
07/21/2011 1:28:03	07/20/2011 21:28:03	Wed	EDT	0.009	60.009	59.967	-0.042	59.968	-0.041	6349		-902	TVA				-2167
07/25/2011 18:39:08	07/25/2011 14:39:08	Mon	EDT	0.019	60.019	59.989	-0.030	59.978	-0.041	6349		-985	PJM				-3242
07/28/2011 18:47:52	07/28/2011 14:47:52	Thu	EDT	-0.004	59.996	59.946	-0.050	59.947	-0.049	6349		-1242	PJM				-2486
07/30/2011 13:41:21	07/30/2011 9:41:21	Sat	EDT	-0.013	59.987	59.945	-0.042	59.947	-0.040	6349		-1386	PJM				-3337

Western Interconnection

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Local Time (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/03/2011 7:17:08	07/03/2011 0:17:08	Sun	PDT	-0.025	59.975	59.929	-0.046	59.901	-0.074	2024		-255	CISO				-526
		07/11/2011 4:17:33	07/10/2011 21:17:33	Sun	PDT	0.005	60.005	59.952	-0.052	59.911	-0.094	2024		-267	SRP				-496
		07/15/2011 2:46:41	07/14/2011 19:46:41	Thu	PDT	-0.035	59.965	59.928	-0.037	59.873	-0.092	2024		-264	BCHA				-706
		07/30/2011 9:17:34	07/30/2011 2:17:34	Sat	PDT	-0.007	59.993	59.937	-0.056	59.907	-0.086	2024		-426	NWMT				-763

ERCOT Interconnection

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Local Time (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/14/2011 20:53:55	07/14/2011 15:53:55	Thu	CDT	0.023	60.023	59.923	-0.100	59.917	-0.106	653		-259	ERCOT				-259
		07/17/2011 15:18:00	07/17/2011 10:18:00	Sun	CDT	-0.005	59.995	59.894	-0.101	59.879	-0.115	653		-144	ERCOT				-143
		07/18/2011 14:13:00	07/18/2011 9:13:00	Mon	CDT	-0.042	59.958	59.863	-0.094	59.879	-0.079	653		-127	ERCOT				-134
		07/21/2011 0:17:10	07/20/2011 19:17:10	Wed	CDT	0.006	60.006	59.811	-0.194	59.799	-0.206	653		-892	ERCOT				-459
		07/24/2011 16:59:24	07/24/2011 11:59:24	Sun	CDT	-0.025	59.975	59.872	-0.102	59.846	-0.128	653		-167	ERCOT				-163
		07/25/2011 22:57:12	07/25/2011 17:57:12	Mon	CDT	0.013	60.013	59.929	-0.084	59.918	-0.095	653		-306	ERCOT				-363

Hydro Quebec

Event ID	Event #	Event Time: UTC (t-0) (MM/DD/YY HH:MM:SS)	Local Time (t-0) Date / Time (MM/DD/YY HH:MM:SS)	Day	Time Zone Pull Dn	Event Frequency Data: A Value Freq Error (from 60)	A Value (t-16 to t-2) average	B Value (t+20 to t+52) average	Hz Delta B-A	Point C (w/in 8 sec after t-0)	Point C delta from Aave	Interconnection Bias Setting MW/0.1 Hz	Resource Information: MW Lost Gross	MW Lost Net	Name BA	Candidate for BA List Y or N	Candidate for beta calc	Load Resources Tripped Before Value B	Point C MW/0.1 Hz
		07/29/2011 2:23:18	07/28/2011 22:23:18	Thu	EDT	0.006	60.006	59.879	-0.127	59.508	-0.498	420		-707	HQ				-559
		07/29/2011 2:23:26	07/28/2011 22:23:26	Thu	EDT	-0.178	59.822	59.891	0.069	59.874	0.052	420		588	HQ				-848
		07/29/2011 5:06:20	07/29/2011 1:06:20	Fri	EDT	-0.030	59.970	60.033	0.064	60.146	0.176	420		329	HQ				-517
		07/30/2011 8:06:58	07/30/2011 4:06:58	Sat	EDT	-0.025	59.975	60.022	0.047	60.109	0.134	420		113	HQ				-239
		07/31/2011 19:32:24	07/31/2011 15:32:24	Sun	EDT	-0.003	59.997	60.081	0.085	60.402	0.405	420		447	HQ				-527

Appendix F – Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard (BAL-003-1)

Event Selection Process

This procedure outlines the ERO process for supporting the Frequency Response Standard (FRS). A procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO will post the suggested modification for a 45-day comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, adopt it with modifications, or reject it. Any approved revision to this procedure will be filed with FERC for informational purposes.

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used by Balancing Authorities (BA) to calculate their Frequency Response to determine:

- whether the BA met its Frequency Response Obligation; and
- an appropriate fixed bias setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS frequency excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the Frequency Response Measure (FRM) calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20–35 frequency excursion events in each interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining FRS compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the interconnection in Table F1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.

ii. Point C is the arrested value of frequency observed within 12 seconds following the start of the excursion.

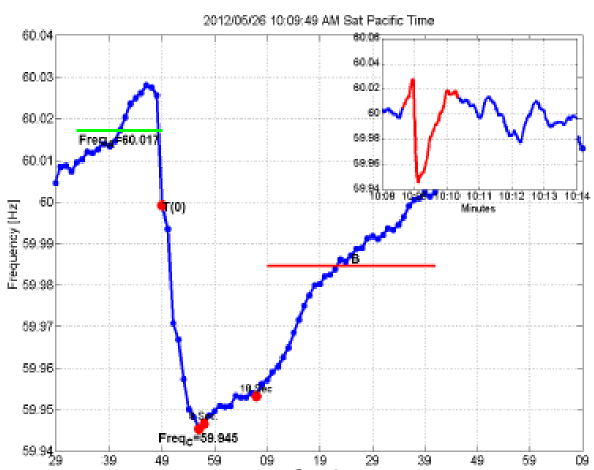
Table F1: Interconnection Frequency Excursion Threshold Values (Hz)

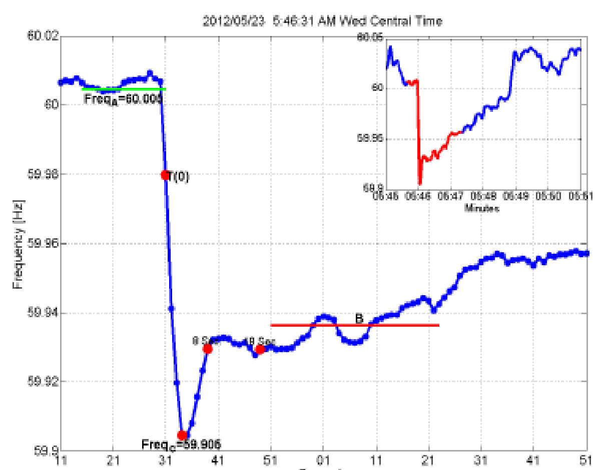
Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
Eastern	0.04	< 59.96	> 60.04
Western	0.07	< 59.95	> 60.05
ERCOT	0.15	< 59.90	> 60.10
Québec	0.30	< 59.85	> 60.15

b. The time from the start of the rapid change in frequency until the point at which frequency has stabilized within a narrow range should be less than 18 seconds.

c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.





5. Excursions that include two or more events that do not stabilize within 18 seconds will not be considered.

6. Frequency excursion events occurring during periods when large interchange schedule ramping or load change is happening, and frequency excursion events occurring within 5

minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

7. The ERO will select the largest (A Value to Point C) two or three frequency excursion events occurring each month. If there are not two frequency excursion events that satisfy the selection criteria in a month, then other frequency excursion events should be picked in the following order of priority:

    1) from the same event quarter of the year
    2) from an adjacent month
    3) from a similar load season in the year (shoulder vs. summer/winter)
    4) the largest unused event

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining FRO compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24 month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of BAL-003-1. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Monthly

Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website:
http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf.

Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events."

Quarterly

The monthly event lists will be reviewed quarterly with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in the “Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard,” events will be selected to populate the FRS Form 1 for each interconnection. Each interconnection’s Form 1 will be posted on the NERC website, in the Resources Subcommittee area under the title “Frequency Response Standard Resources.” The updated Form 1 documents will be posted at the end of each quarter listed above after a review by the NERC RS Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each interconnection, which will contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year’s Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will error check and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Appendix G – Statistical Analysis of Frequency Response (Eastern Interconnection)

Statistical Analysis of Frequency Response

Eastern Interconnection August 7, 2012

Introduction

An interconnected electric power system is a complex system that must be operated within a safe frequency range to reliably maintain the instantaneous balance between generation and load, and is directly reflected in the frequency of the interconnection. Frequency Response is one measurement of how a power system has performed in response to the sudden loss of generation or load. This white paper analyzes the Frequency Response data for the Eastern Interconnection using statistical methods to study the probability distribution of the Frequency Response and its changes from year-to-year, as well as construct a set of variables that strongly influence Frequency Response.

Objectives and Method

The main goals of the statistical analysis of the Frequency Response data for the Eastern Interconnection are to study the:

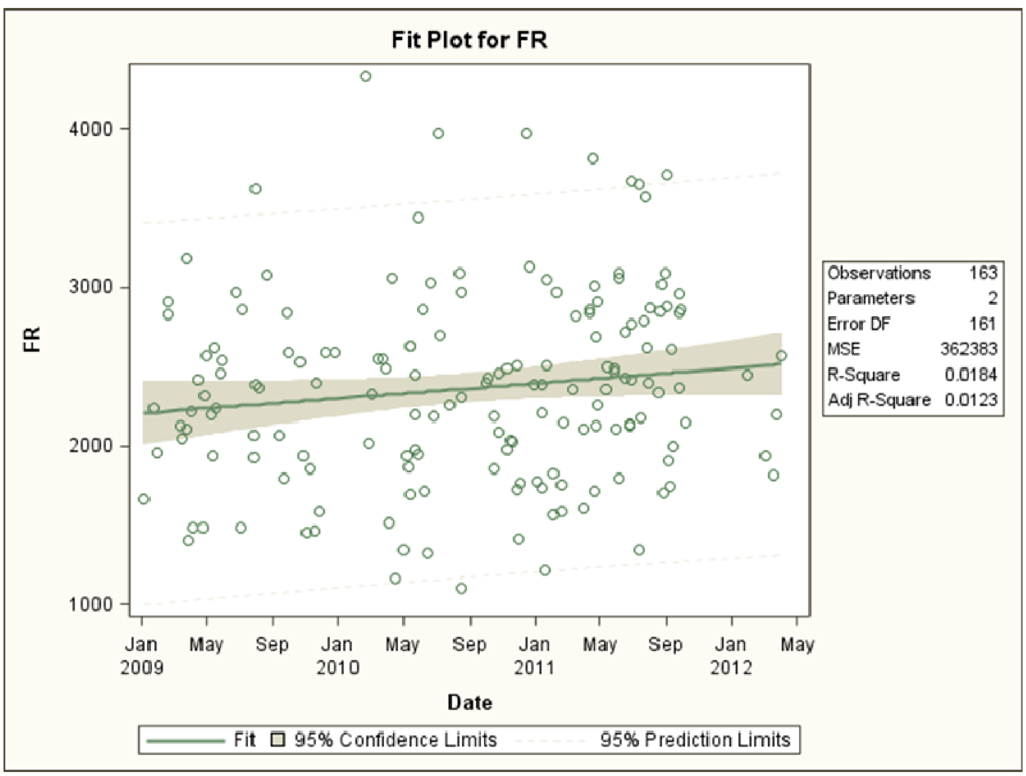
1. time trend of Frequency Response by selecting an appropriate model describing the relationship between a point in time when an event happens and the absolute value of Frequency Response for this event, and to use this model for Frequency Response forecasting with a given confidence level;
2. probability distribution of the Frequency Response and its changes over the years;
3. seasonal changes in Frequency Response distribution and correlation between Frequency Response value and season when the event happened (summer/non-summer);
4. impact of pre-disturbance frequency on Frequency Response;
5. impact of on-peak/off-peak hours on Frequency Response;
6. impact of interconnection load on Frequency Response; and
7. hierarchy of these explanatory factors of Frequency Response.

The analysis uses the Frequency Response dataset for the Eastern Interconnection for the calendar years 2009-2011 and the first three months of 2012. The size of this dataset is 163 frequency events (with 44 observations for the year of 2009, 49 for 2010, 65 for 2011, and 5 for 2012). Since interconnection load data are not yet available for 2012, the part of the study involving interconnection load deals with the 158 Frequency Response events occurred in 2009-2011. For purposes of this whitepaper, Frequency Response pertains to the absolute value of Frequency Response.

Key Findings

1. A linear regression equation with the parameters defined in the Appendix of this whitepaper is an adequate statistical model to describe a relationship between time (predictor) and Frequency Response (response variable). The graph of the linear regression line and Frequency Response scatter plot is given in Figure G1. For the dataset, the regression line has a small positive slope estimate, meaning that the Frequency Response variable has a slowly increasing general trend in time. The value of the slope estimate is 0.00000303805 (the time unit is a second). This means that, on average, Frequency Response increases daily by 0.26 MW/0.1Hz, monthly by 7.87 MW/0.1 Hz, and annually by 95.81 MW/ 0.1Hz (for a month with 30 days , and a year with 365 days). A 90% confidence interval for slope, CI=[-0.00000041605, 0.00000649214], has a negative left-end point (the same is true for a 95% CI and a 99% CI). With new data available the trend line can (a) increase its positive slope, (b) change the positive slope to a slight negative one, or (c) become essentially flat that will correspond to an absence of a correlation between time and Frequency Response.

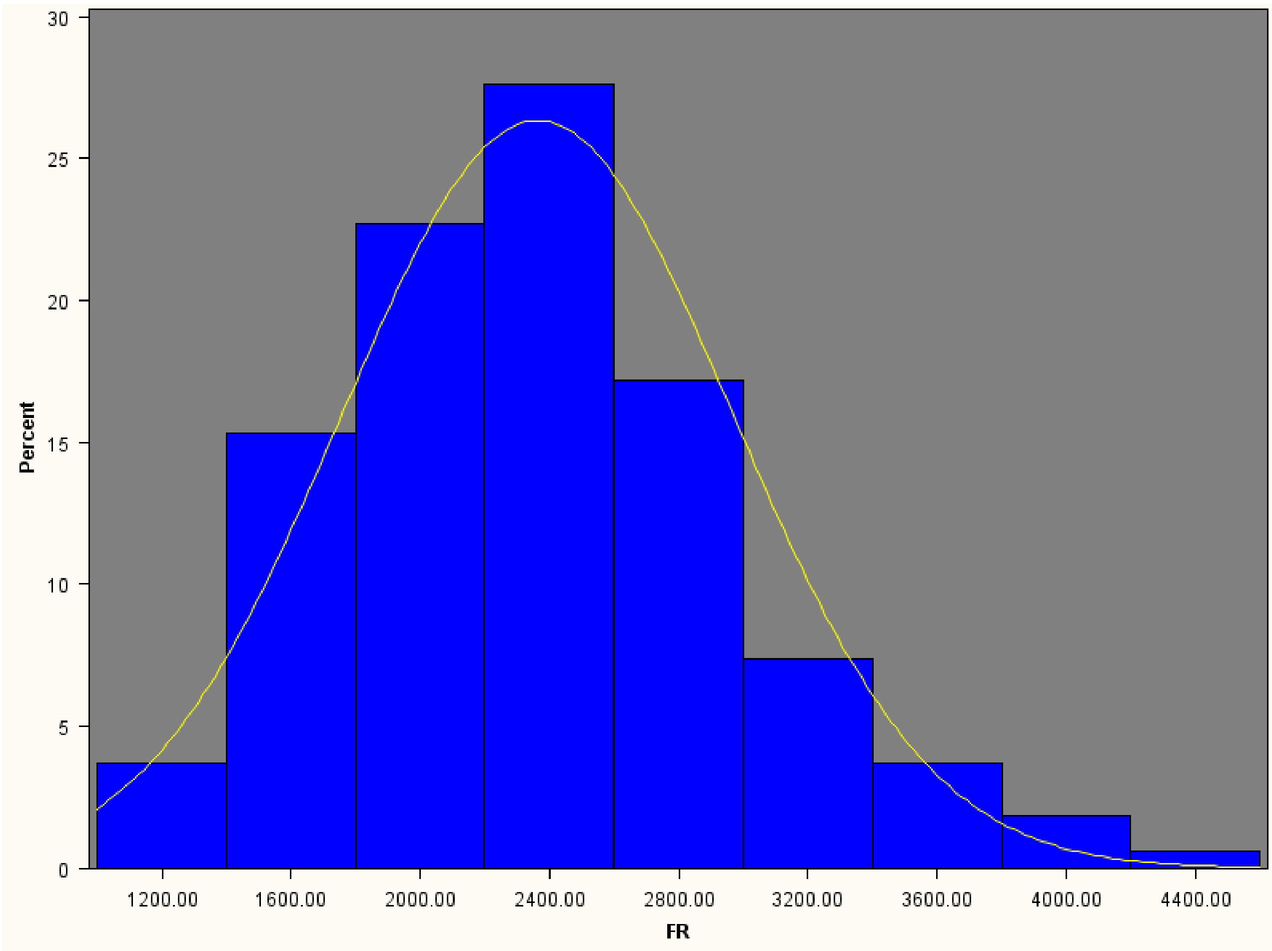
Figure G1: Frequency Response Scatter Plot



2. The probability distribution of the whole Frequency Response dataset is approximately normal with the expected Frequency Response of 2363 MW/0.1 Hz and the standard deviation of 605.7 MW/0.1 Hz as shown in Figure G2. The comparative statistical analysis for every pair of years shows that the changes in the 2010 data versus the 2009 data (and in the 2011 data versus the 2010 data) are not statistically significant enough to lead to the conclusion that the mean value of Frequency Response for any two consecutive years changes. However, the data for 2009 and 2011 differ at the level that results in accepting

the hypothesis that the expected value of Frequency Response for 2011 is greater than for 2009.

Figure G2: Probability Distribution of the Entire Frequency Response Data Set



3. A season (summer/non-summer) is a significant contributor to the variability of Frequency Response. There is a positive correlation of 0.24 between the indicator function for summer (defined as 1 for events that occur in June–August and 0 otherwise) and Frequency Response: summer events have a statistically significantly greater expected Frequency Response (the sample mean equals to 2598MW/0.1 Hz) than non-summer events (the mean equals to 2271 MW/0.1 Hz).

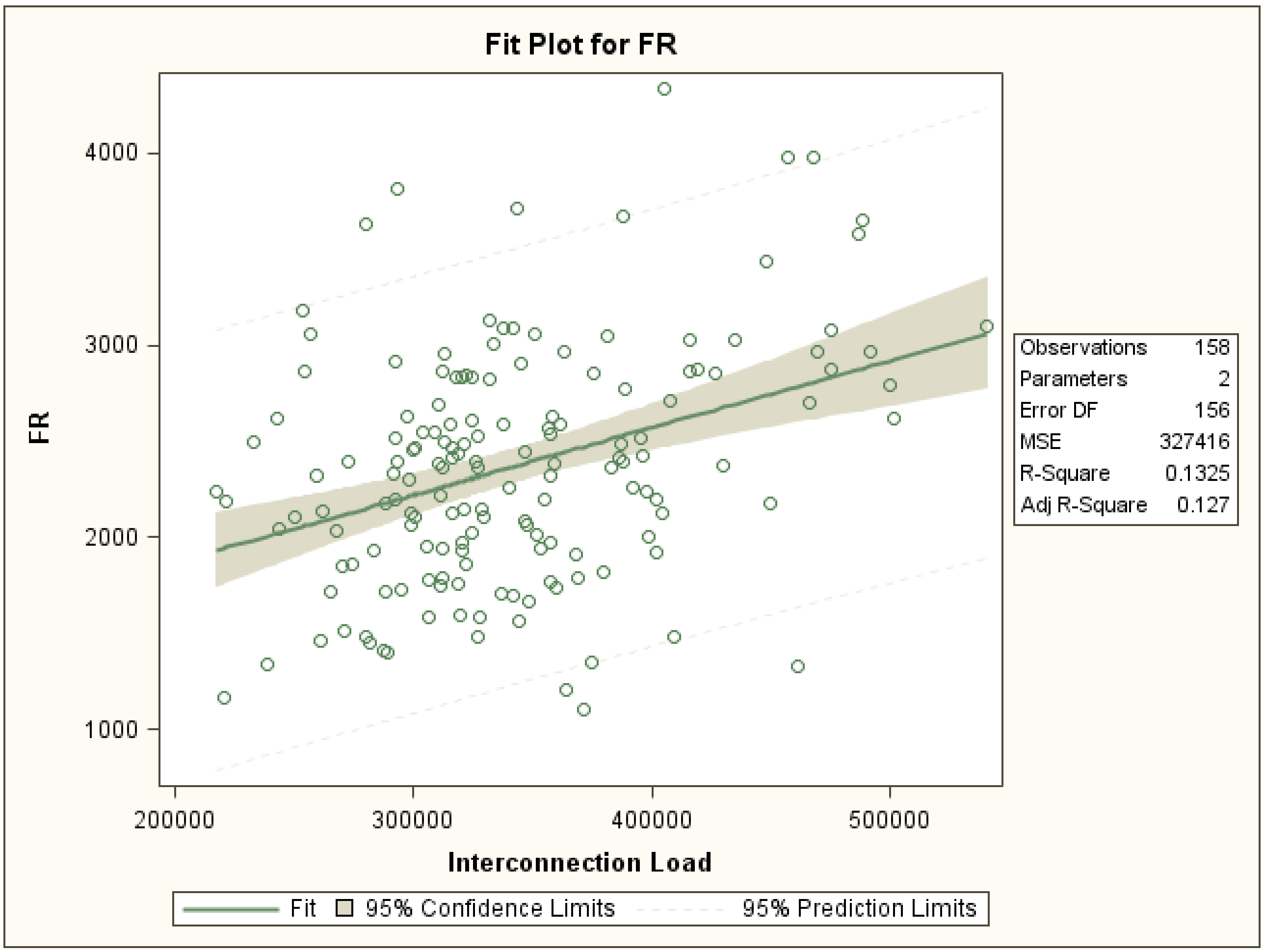
4. Pre-disturbance (average) frequency (A) is another significant contributor to the variability of Frequency Response. There is a negative correlation of -0.27 between the indicator function of A>60 Hz and Frequency Response: the events with A>60 Hz have a statistically significantly smaller expected Frequency Response (the sample mean equals to 2188 MW/0.1 Hz) than the events with A≤60 Hz (the mean equals to 2513 MW/0.1 Hz).

5. According the NERC definition, for Eastern Interconnection on-peak hours are designated as follows: Monday to Saturday hours from 0700 to 2200 (Central Time) excluding six holidays (New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day). It turns out that on-peak/off-peak variable is not a statistically significant

contributor to the variability of Frequency Response. There is a positive correlation of 0.06 between the indicator function of on-peak hours and Frequency Response; however, difference in average Frequency Response between on-peak events and off-peak events is not statistically significant and could occur by chance (P-value is 0.49).

6. There is a strong positive correlation of 0.364 between interconnection load and Frequency Response for the 2009-2011 events; this correlation indicates to a statistically significant linear relationship between interconnection load (predictor) and Frequency Response (response variable). The graph of the linear regression line and Frequency Response scatter plot is given in Figure G3. For the dataset, the regression line has a positive slope estimate of 0.00349; thus, the Frequency Response variable increases when interconnection load grows. On average, when interconnection load changes by 1000 MW, Frequency Response changes by 3.5 MW/0.1Hz.

Figure G3: Linear Regression for Frequency Response and Interconnection Load



7. For the 2009–2011 dataset, five variables (time, summer, high pre-disturbance frequency, on-peak/off-peak hour, interconnection load) have been involved in the statistical analysis of Frequency Response. Four of these (time, summer, on-peak hours, and interconnection load) have a positive correlation with Frequency Response (0.16, 0.24, 0.06, and 0.36,

respectively), and the high pre-disturbance frequency has a negative correlation with Frequency Response (-0.26). The corresponding coefficients of determination R^2 are 2.6%, 5.8%, 0.4%, 13.3% and 6.9%. These values indicate that about 2.6% in variability of Frequency Response can be explained by the changes in time, about 5.8% of Frequency Response variability is seasonal, 0.4% is due to on-peak/off-peak changes, 13.3% is the effect of the interconnection load variability, and about 6.9% can be accounted for by a high pre-disturbance frequency. However, the correlation between Frequency Response and On-Peak hours is not statistically significant and with the probability about 0.44 occurred by mere chance (the same holds true for the corresponding R^2). Therefore, out of the five parameters, interconnection load has the biggest impact on Frequency Response followed by the indicator of high pre-disturbance frequency. A multivariate regression with interconnection load and A>60 as the explanatory variables for Frequency Response yields a linear model with the best fit (it has the smallest mean square error among the linear models with any other set of explanatory variables selected from the five studied). Still, together these two factors can account for about 20% in variability of Frequency Response. Therefore, there are other parameters that affect Frequency Response, have a low correlation with those studied, together account for a remaining share in Frequency Response variability, and minimize a random error variance. Note that interconnection load is positively correlated with summer (0.55), on-peak hours (0.45), and Date (0.20) but uncorrelated with A>60 (P-value of the test on zero correlation is 0.90).

Explanatory Variables for EI Frequency Response (2009-2011)

Variable X	Sample Correlation (X,FR)	P-value	Linear Regression Statistically Significant?	Coefficient of Determination R^2 (Single Regression)
Interconnection Load	0.36	<0.0001	Yes	13.3%
A>60	-0.26	0.0008	Yes	6.9%
Summer	0.24	0.0023	Yes	5.8%
Date	0.16	0.044	Yes	2.6%
On-Peak Hours	0.06	0.438	No	N/A

Appendix – Background Materials

Frequency Response is a metric used to track and monitor Interconnection Frequency Response. Frequency Response[2] is a measure of an interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. It is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. The metric measures the average Frequency Response for all events where frequency drops more than the interconnection's defined threshold as shown in Table 1.

Frequency Response Definition

For a given interconnection, Frequency Response is defined as the sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

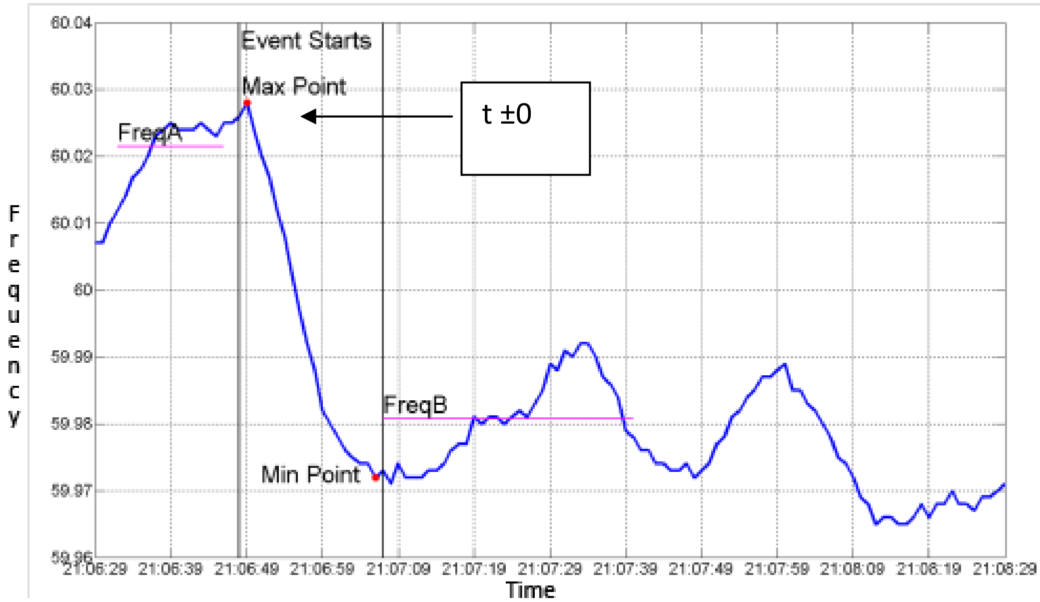
Table 1: Frequency Event Triggers for Data Collection

Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	40	800	15
Western	70	700	15
ERCOT	90	450	15
Québec	300	450	15

The change in frequency is the difference between pre-disturbance frequencies A and setting frequency B. Figure 3 shows the criteria for calculating average values A and B. The event starts at time t ±0. Value A is the average from t -16 to t -2 and Value B is the average from t +20 to t +52. These lengths of time used to calculate these values accounts for the variability in Supervisory Control and Data Acquisition (SCADA) scan rates that vary from 2 to 6 seconds in the multiple-Balancing Authority interconnections. For Balancing Authority SCADA data, t ±0 represents the first scan of data that is part of the disturbance. Value A is the average of all SCADA scans between 2 and 16 seconds before t ±0. Value B is the average of all SCADA scans between 20 and 52 seconds after t ±0.

[2] Frequency Response is in fact a negative value. However to reduce confusion for the reader, Frequency Response is expressed in this report as positive values (the absolute value of the actual calculated value).

Figure 3: Criteria for Calculating Value A and Value B



The actual MW loss for the flagged frequency events is determined jointly by NERC and Regional Entity situation awareness staff. Both the change in frequency and the MW loss determine whether the event qualifies for further consideration in the monthly frequency event candidate list.

Statistical Analysis

Linear Regression for Time Trend

Assumptions: Frequency Response and time are related by the following regression equation:

$$FR = A * Time + B + \varepsilon$$

Where:

- $Time$ variable represents a time (year, month, day, hour, minute, second) when a Frequency Response event happened. For each event the Frequency Response is calculated and recorded. This record represents an observation from the dataset. Time is an explanatory variable (predictor, regressor) of the linear regression;
- FR is the Frequency Response value measured in MW/0.1 Hz (response variable of the model);
- A is a slope of the regression line;
- B is an intercept of the regression line; and
- ε is a random error which has a centered normal distribution with variance σ^2.

A SAS program for the linear regression analysis yields the following results shown in figure G3.

(a) The equation of the regression line derived by the least squares method is $y = 0.00000304x - 2493.41315$ with $x = Time(sec)$ elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS) and the time of a FR event;
(b) Estimate for the variance σ^2 of the random error ε is 362,383 and for the standard deviation of ε is 601.98255;
(c) Statistical test for significance of the_regression (based on the analysis of variance approach) is an important part of assessing the adequacy of the linear regression model for time and FR variables. The procedure tests a null-hypothesis that the slope A = 0 versus an alternative hypothesis that it is not 0. Sample value of F-statistic, 3.0170, has P-value of 0.0843 implying that the null hypothesis should be rejected (and the alternative hypothesis accepted) at any significance level above 0.0843. Therefore, the data are statistically significant to support a hypothesis about a linear relationship between time and Frequency Response assuming that the 8.43% significance level (i.e., the probability to reject the null hypothesis when it is true) is appropriate for the model selection. Alternatively, the hypothesis about the correlation coefficient ρ(time, FR) can be tested (with the null hypothesis ρ=0). These tests are equivalent and result in the same P-values for their test statistics.

Another important part of the verification of the linear regression model is testing the assumptions on the random error ε. Student's t-test on location and goodness-of-fit test for normality both result in acceptance the corresponding null-hypothesis (with P-values of 1.0000 and 0.881, respectively).

The linear regression equation with the parameters defined above is an adequate statistical model to describe the relationship between variables time of a FR event and Frequency Response value for this event. For the dataset, the regression line has a small positive slope estimate, meaning that Frequency Response variable has a slowly increasing general trend in time. However, the value of this slope estimate is very small, and confidence intervals for slope at 90%, 95% and 99% levels all have a negative left-end point. By using T-distribution for the slope estimator, we estimate that the probability that the slope of the regression is negative is below 5%.

The coefficient of determination R^2 for the linear regression model equals to 0.0184. This small value indicates very low degree of dependence of Frequency Response on time variable. Essentially, the linear regression model connecting FR and time accounts for 1.8% of variability in the Frequency Response data.

The random error ε has a large estimated variance that makes the "error" term of the linear regression equation a major component of the Frequency Response value. Our next goal is to consider the Frequency Response data as observations of a random variable independent of time and to study properties of its distribution.

Distribution of Frequency Response

Goodness-of-Fit test for normality of the distribution of the Frequency Response data results in acceptance on the null hypothesis at a significance level below 0.177 (including the standard levels of 1%, 5% and 10%). The sample estimate for the expected Frequency Response equals to 2363 MW/0.1 Hz and the sample standard deviation is 605.7 MW/0.1 Hz.

Since for each full year (2009, 2010, and 2011) the sample size of the Frequency Response data exceeds 40, we ran a large-sample test for the difference in the mean Frequency Response for 2009 versus 2010, 2010 versus 2011, and 2009 versus 2011. The null hypothesis that the difference is zero is accepted when the 2009 data are compared to the 2010 data, and when the 2010 data are compared to the 2011 data at any standard significance level (P-values of the two-sided tests are 0.54 and 0.28, respectively). For the 2009 versus 2011 comparison, the test result is not that conclusive (its P-value equals to 0.03 and, therefore, the null hypothesis should be rejected at the 5% and 10% significance levels but is accepted at the 1% level if tested versus an alternative hypothesis that the 2011 mean value is greater than the 2009 mean value).

Seasonal Variability of Frequency Response

Let a function summer be defined as follows: it equals to 1 for Frequency Response events that occur in June-August and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for summer events and non-summer events, respectively. Summer Frequency Response set has 46 observations and non-summer set has 117 observations. The sample mean and the sample variance for the first dataset are 2597.7 MW/0.1 Hz and 675.5 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2270.9 MW/0.1 Hz and 552.2 MW/0.1 Hz. A large-sample test for the difference in the mean Frequency Response for these distributions results in rejection of the null hypothesis that the difference is zero and acceptance of an alternative hypothesis that the expected Frequency Response for summer events is greater than for other events (P-value of the one-sided z-test is 0.0018).

Variables summer and Frequency Response are positively correlated (with the correlation equal to 0.24351), and the coefficient of determination R^2 of the linear regression model is 0.0593. The null hypothesis about zero correlation (no linear relationship between FR and summer) should be rejected (P-value is 0.0017). This analysis indicates that seasonality is a significant factor affecting Frequency Response: almost 6% of its variability is the seasonal variability.

Impact of Pre-Disturbance Frequency

Let a function high pre-disturbance frequency be defined as follows: it equals to 1 for Frequency Response events with A>60 Hz and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for events with A>60 Hz and events with A≤60 Hz, respectively. High pre-disturbance frequency set has 75 observations and its complement has 88 observations. The sample mean and the sample variance for the first dataset are 2187.6 MW/0.1 Hz and 531.5 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2512.8 MW/0.1 Hz and 627.4 MW/0.1 Hz. A large-sample test for the difference in the mean Frequency Response for these distributions results in rejection of the null hypothesis that the difference is zero and acceptance of an alternative hypothesis that the expected Frequency Response for events with A>60 Hz is smaller than for other events (P-value of the one-sided z-test is 0.0002).

Variables high pre-disturbance frequency and Frequency Response are negatively correlated (with the correlation equal to -0.26844), and the coefficient of determination R^2 of the linear regression model is 0.0721. The null hypothesis about zero correlation (no linear relationship between FR and high pre-disturbance frequency) should be rejected (P-value is 0.0005). This analysis indicates that the high pre-disturbance frequency is a factor that accounts for 7.2% of the Frequency Response variability. In fact, out of the four variables involved in this study (time, summer, high pre-disturbance frequency, on-peak/off-peak hours), it is the biggest contributor to the variability of Frequency Response.

Impact of On-Peak/Off-Peak hours

Let a function on-peak hour be defined as follows: it equals to 1 for Frequency Response events occurred during an on-peak hour and 0 otherwise. The FR dataset is therefore divided in two subsets: the Frequency Response data for on-peak hours and off-peak hours, respectively. On-peak set contains 108 observations, and off-peak set has 55 observations. The sample mean and the sample variance for the first dataset are 2386.9 MW/0.1 Hz and 602.9 MW/0.1 Hz, respectively. The sample mean and the sample variance for the second dataset are 2316.6 MW/0.1 Hz and 614.1 MW/0.1 Hz. A large-sample test for the difference in the expected Frequency Response for these distributions results in acceptance of the null hypothesis that the difference is zero and rejection of an alternative hypothesis that the expected Frequency Responses for on-peak events and off-peak events are different (P-value of the two-sided z-test is 0.49).

Variables on-peak hour and Frequency Response are positively correlated (with the correlation equal to 0.005505), and the coefficient of determination R^2 of the linear regression model is 0.0030. However, the correlation is not statistically significant since the null hypothesis about zero correlation (no linear relationship between FR and on-peak hour) should be accepted (P-value is 0.4852). The same is true for the coefficient of determination: there is a high probability that on-peak hours have no explanatory power in the Frequency Response variability. Out of the four variables involved in this study (time, summer, high pre-disturbance frequency, on-peak/off-peak hours), it is the only factor with no statistically significant impact on Frequency Response.

Linear Model that relates Frequency Response to Interconnection Load

Assumptions: Frequency Response and interconnection load are related by the following regression equation:

$$FR = C * IL + D + \varepsilon$$

Where:

- IL is the value of interconnection load (in MW) for a Frequency Response event.
- FR is the Frequency Response value measured in MW/0.1 Hz (response variable of the model);

- C is a slope of the regression line;
- D is an intercept of the regression line; and
- ε is a random error which has a zero mean and variance of σ^2.

A SAS program for the linear regression analysis yields the following results shown in figure G3.:

(a) The equation of the regression line derived by the least squares method is

$y = 0.00349x + 1174.09949$;

(b) Estimate for the variance σ^2 of the random error ε is 327,416 and for the standard deviation of ε is 572.2; and

(c) Statistical test for significance of the regression (based on the analysis of variance approach) is an important part of assessing the adequacy of the linear regression model for interconnection load and FR variables. The procedure tests a null-hypothesis that the slope $C = 0$ versus an alternative hypothesis that it is not 0. Sample value of F-statistic, 23.83, has P-value of 0.0001 implying that the null hypothesis should be rejected (and the alternative hypothesis accepted) at any significance level above 0.0001. Therefore, the data are statistically significant to support a hypothesis about linear relationship between interconnection load and Frequency Response. Alternatively, the hypothesis about the correlation coefficient ρ between interconnection load and Frequency Response can tested (with the null hypothesis ρ=0). These tests are equivalent and result in the same P-values for their test statistics.

The coefficient of determination R^2 for the linear regression model equals to 0.1325. This value indicates high degree of dependence of Frequency Response on interconnection load. Essentially, the linear regression model connecting FR and interconnection load accounts for about 13.3% of variability in the Frequency Response data.

Multiple Linear Regression

A statistically significant linear regression model connects interconnection load and high pre-disturbance frequency (regressors) and Frequency Response (response variable). The estimates of the linear regression coefficients are listed in the Table 2 (P-value of the model is below 0.0001). An error term, ε, has a zero mean and the standard deviation of 551 MW/0.1 Hz. This multiple regression model accounts for 19.96% of the variability in Frequency Response data.

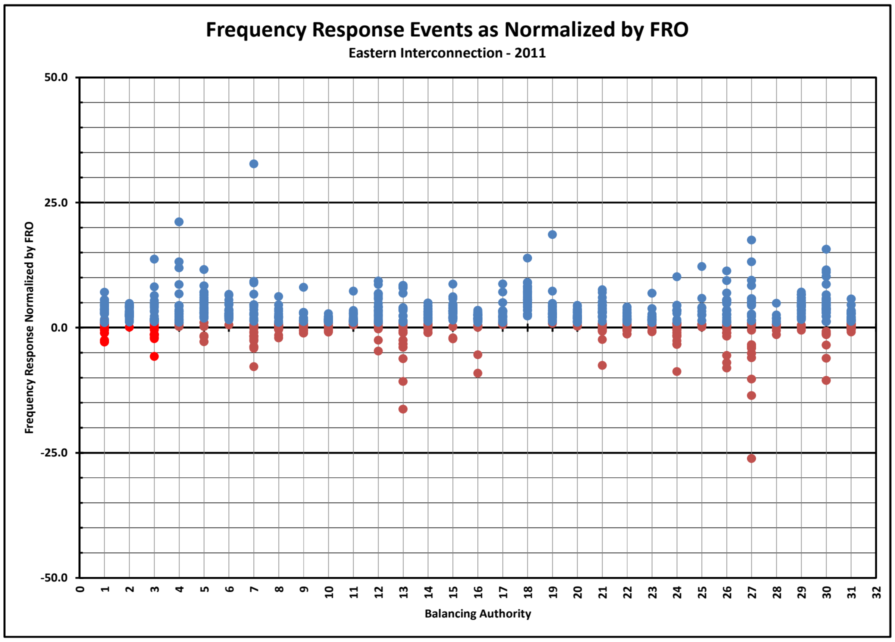
Table 2: Parameter Estimates of Multiple Regression

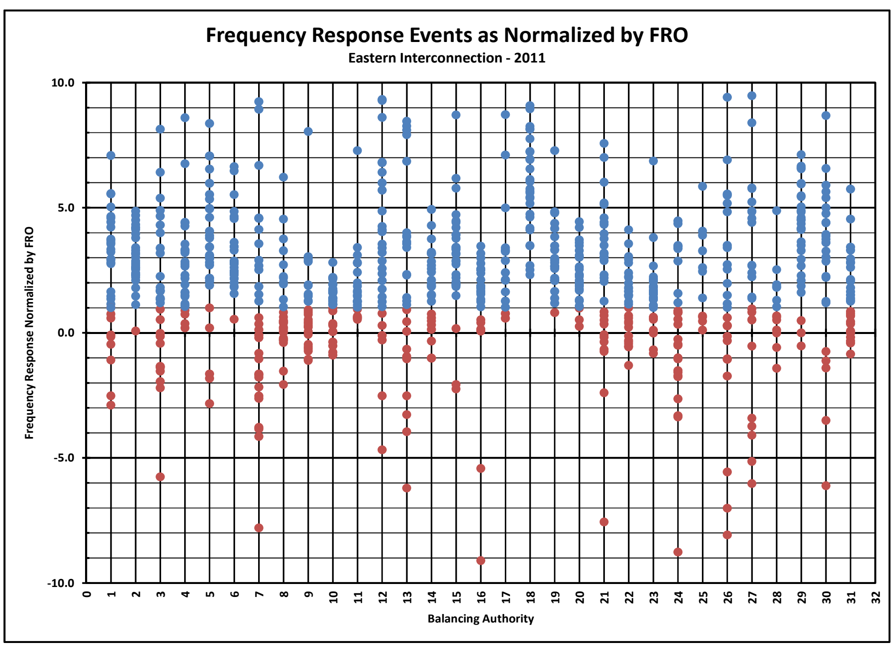
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	1325.96255	243.49079	5.45	<.0001
A>60	1	-317.95091	88.191	-3.61	0.0004
Interconnection Load	1	0.00347	0.00068929	5.03	<.0001

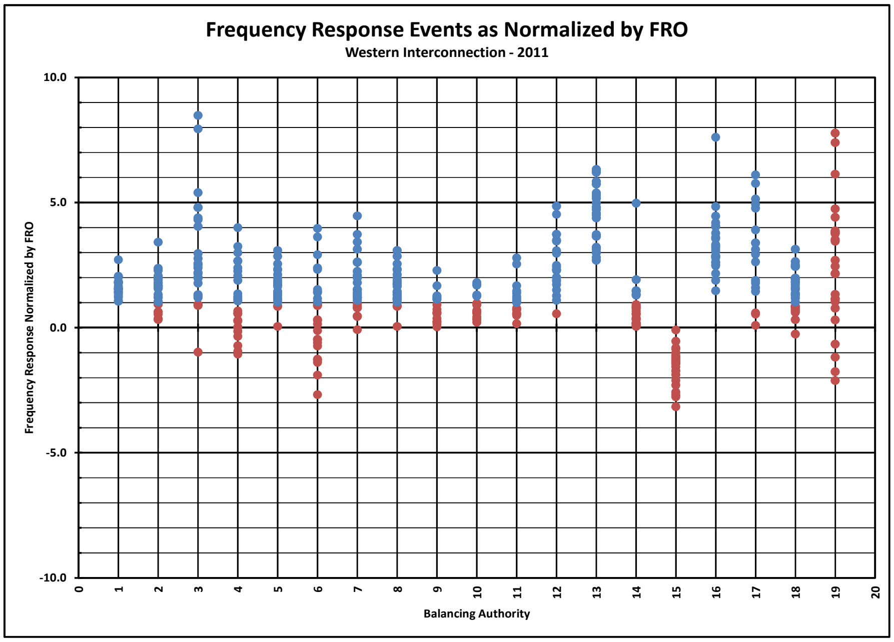
Note that even though time and summer both have a statistically significant positive correlation with Frequency Response, adding one or both of them to the set of explanatory variables does not improve the linear model. This can be explained by a high correlation between interconnection load and summer (0.55) and time (0.20), respectively: addition of these variables does not increase the explanatory power of the model enough to offset an increase of its cumulative error.

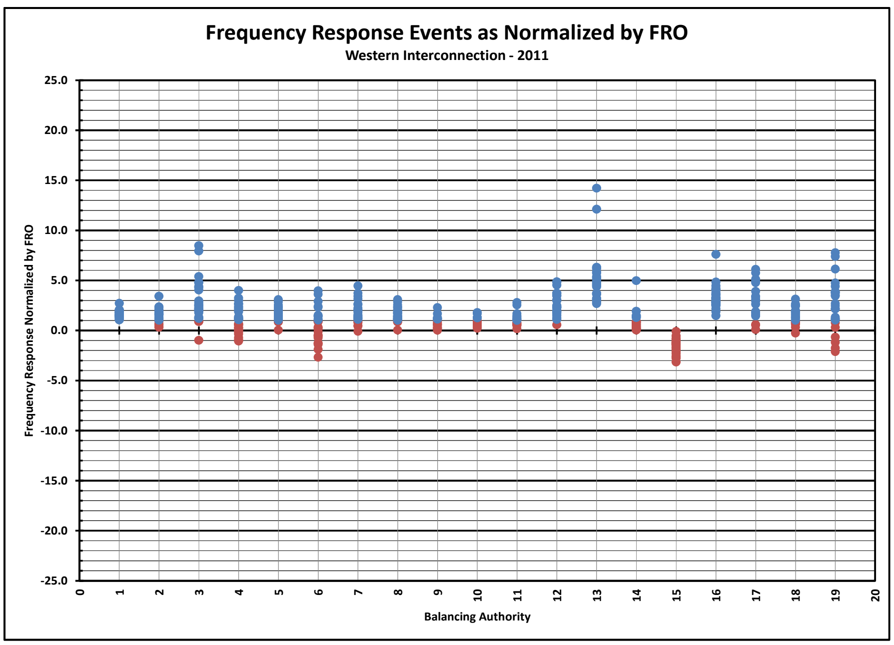
Appendix H – Frequency Response Field Trial Analysis Graphs

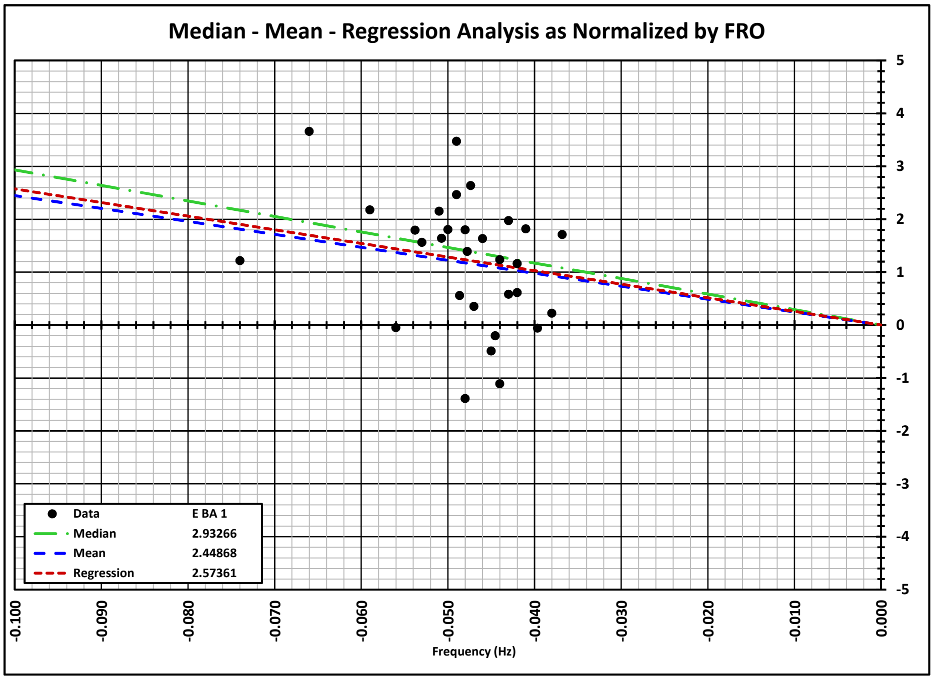
NOTE: These are the background graphics of the Frequency Response Field Trial Analysis of BA performance measurements.

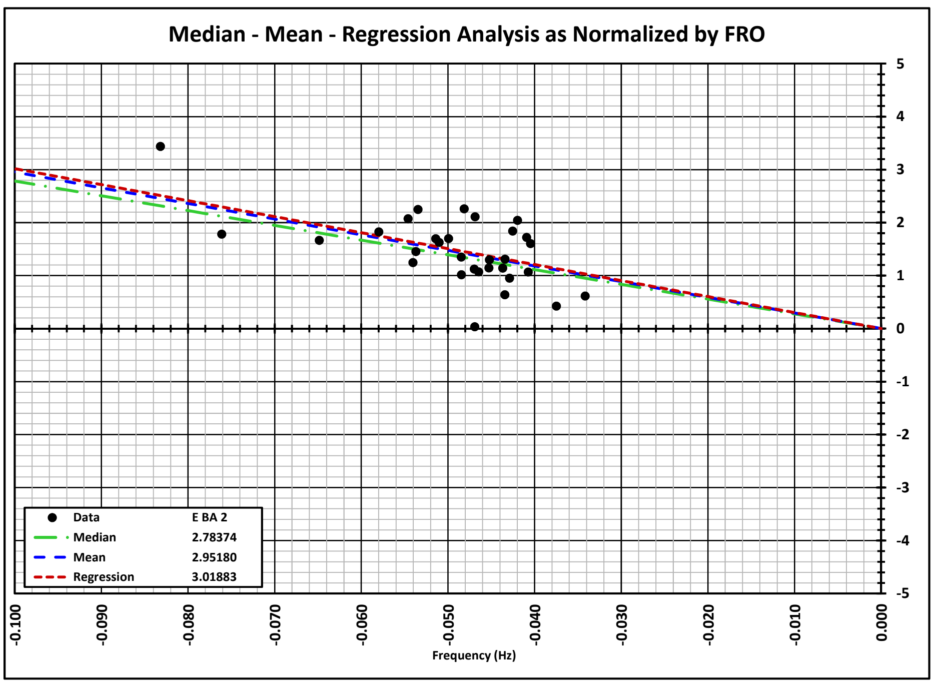





Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 1
Median 2.93266
Mean 2.44868
Regression 2.57361
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 2
Median 2.78374
Mean 2.95180
Regression 3.01883
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
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-0.010
0.000
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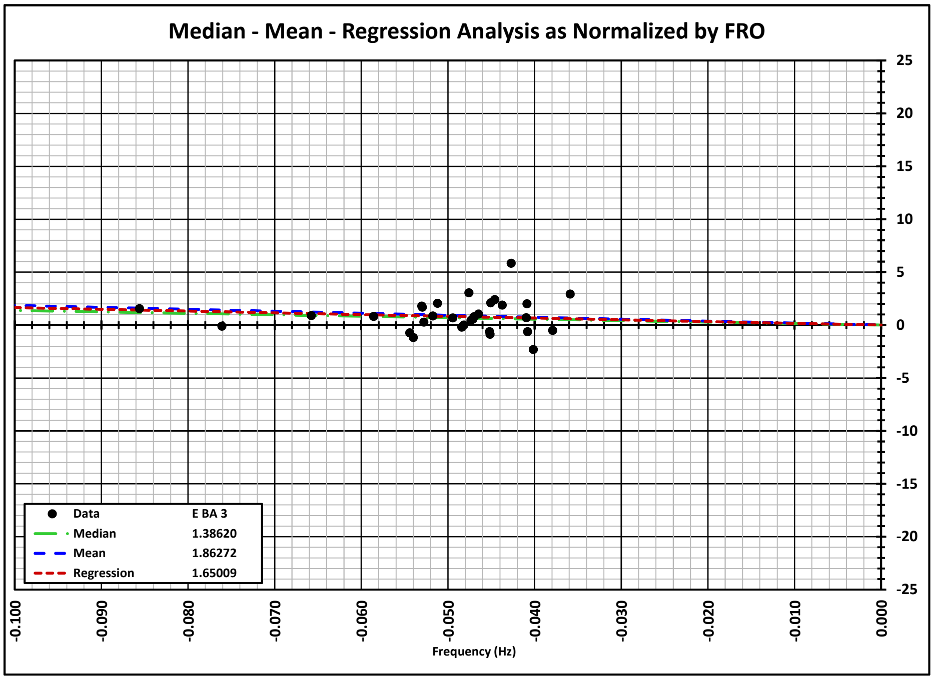
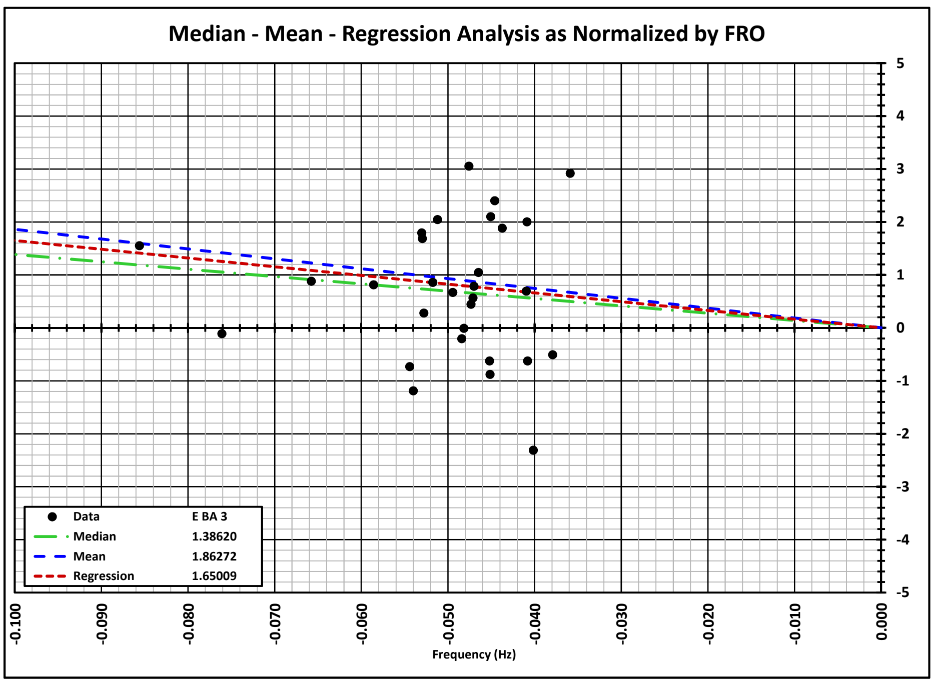
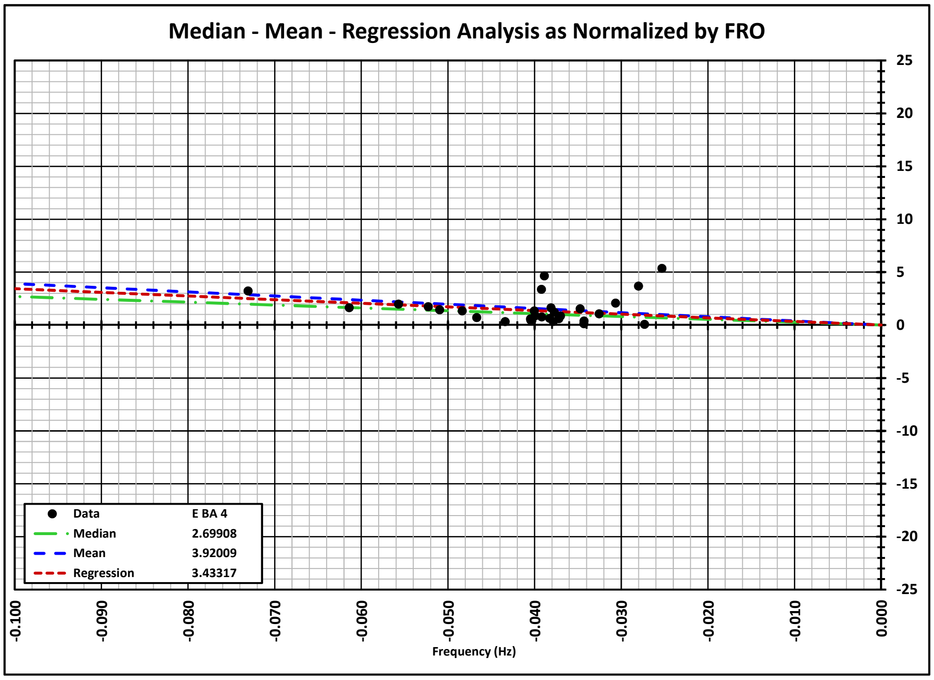
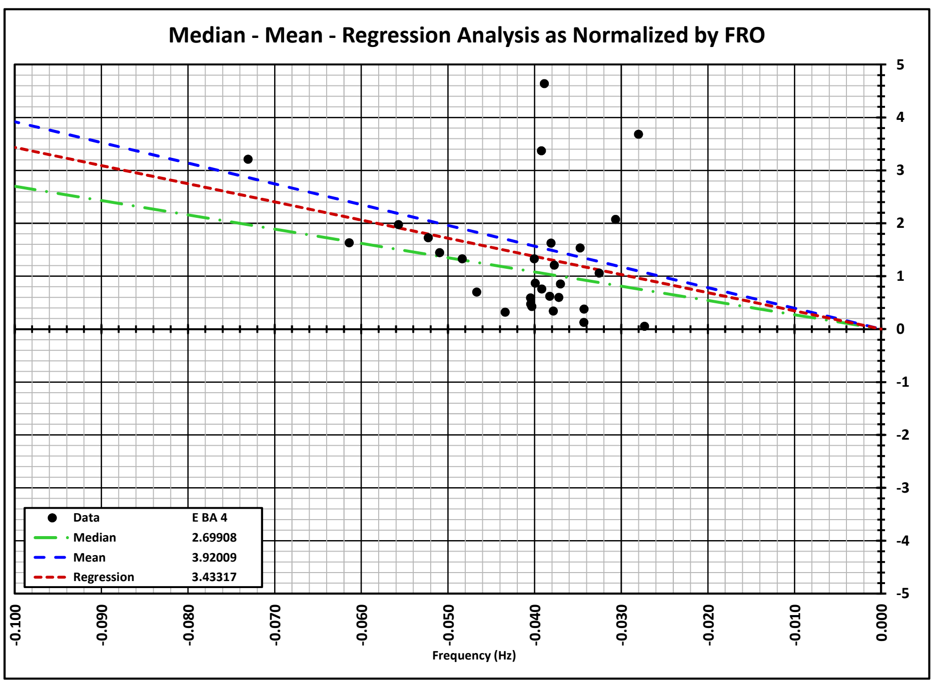
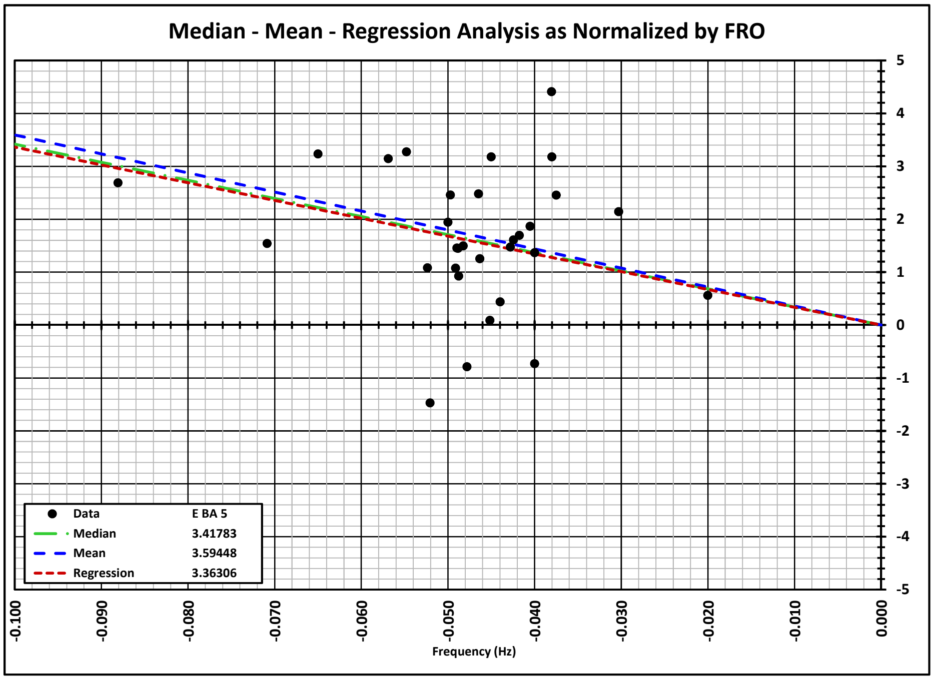
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 3
Median 1.38620
Mean 1.86272
Regression 1.65009
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 3
Median 1.38620
Mean 1.86272
Regression 1.65009
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 4
Median 2.69908
Mean 3.92009
Regression 3.43317
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 4
Median 2.69908
Mean 3.92009
Regression 3.43317
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 5
Median 3.41783
Mean 3.59448
Regression 3.36306
Frequency (Hz)
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-0.090
-0.080
-0.070
-0.060
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-0.040
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0.000
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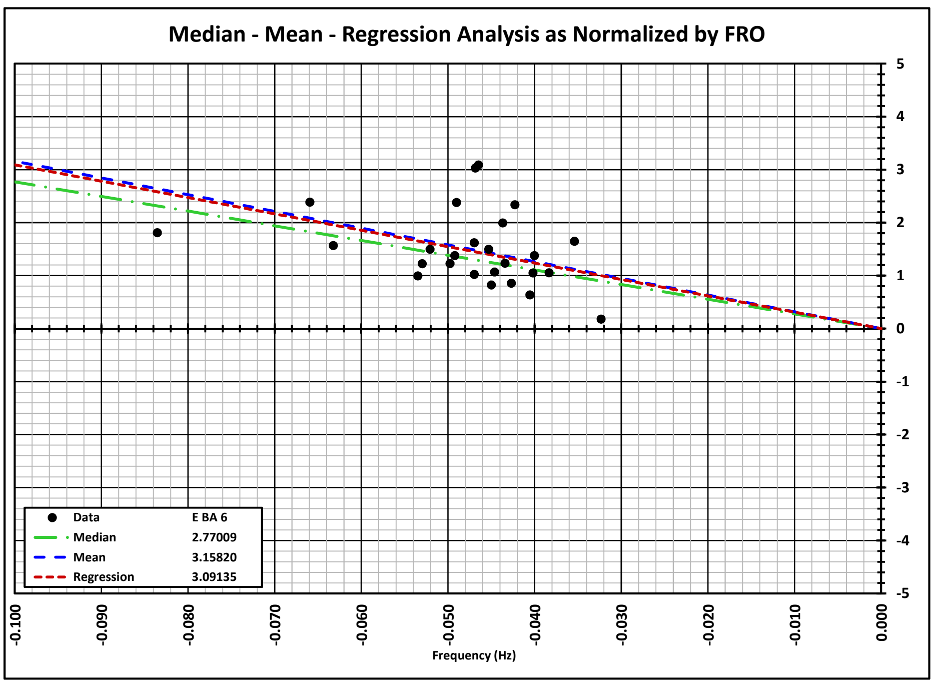
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 6
Median 2.77009
Mean 3.15820
Regression 3.09135
Frequency (Hz)
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-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
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0.000
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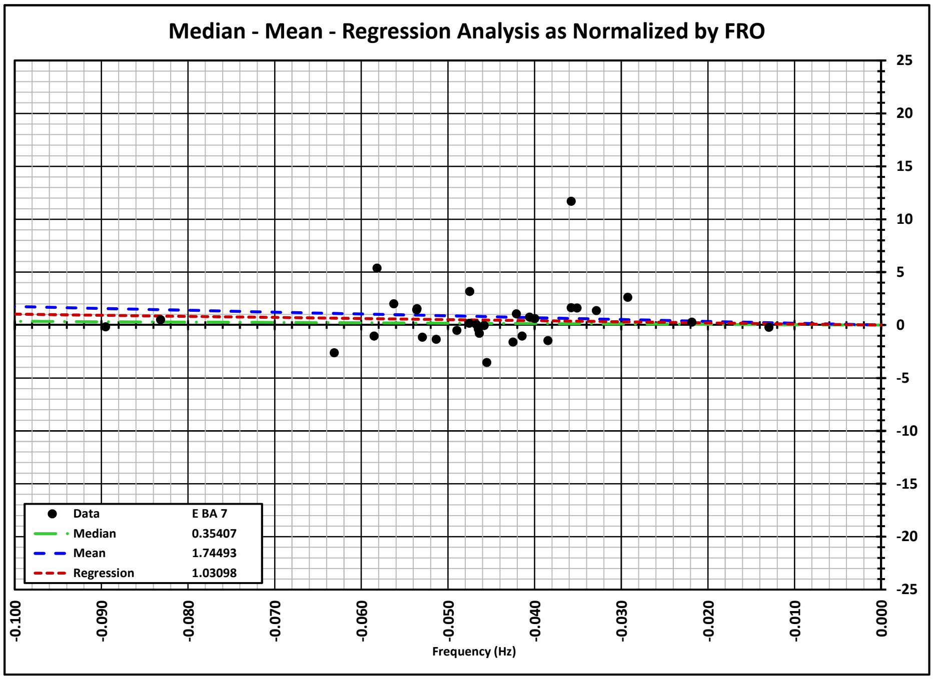
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
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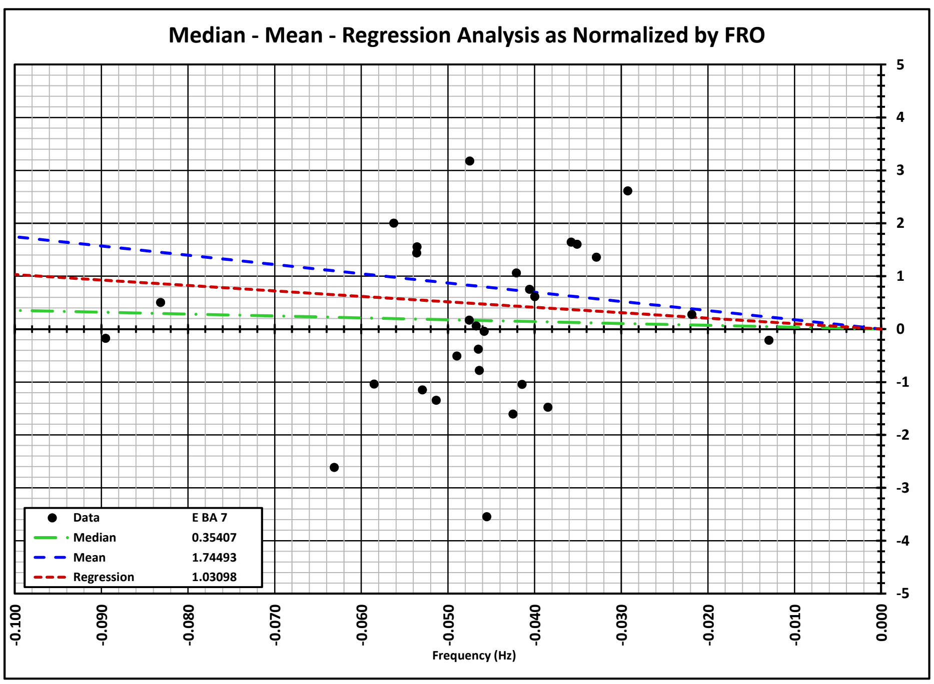
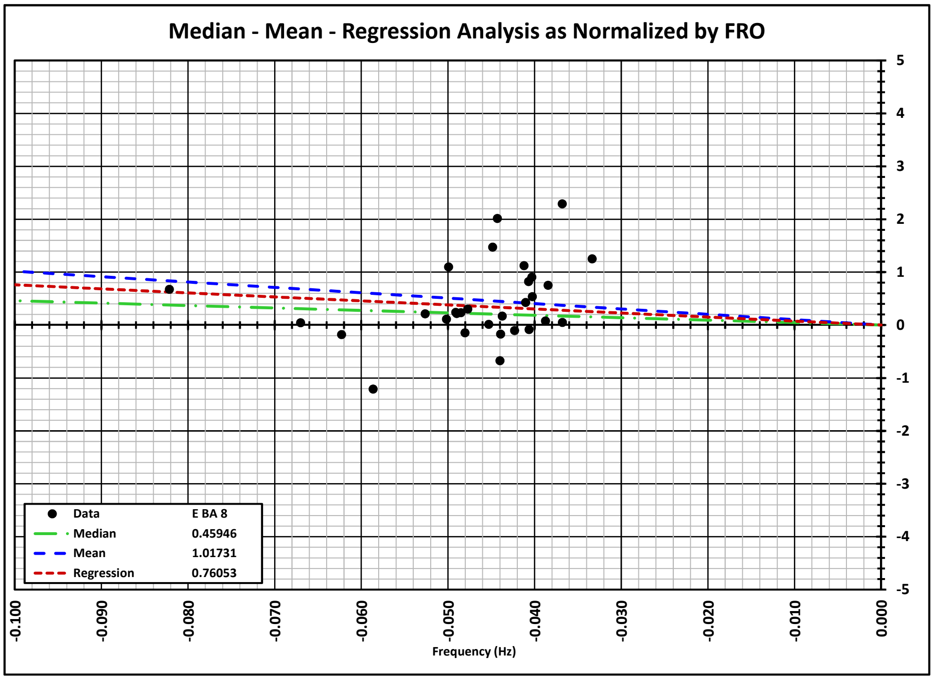
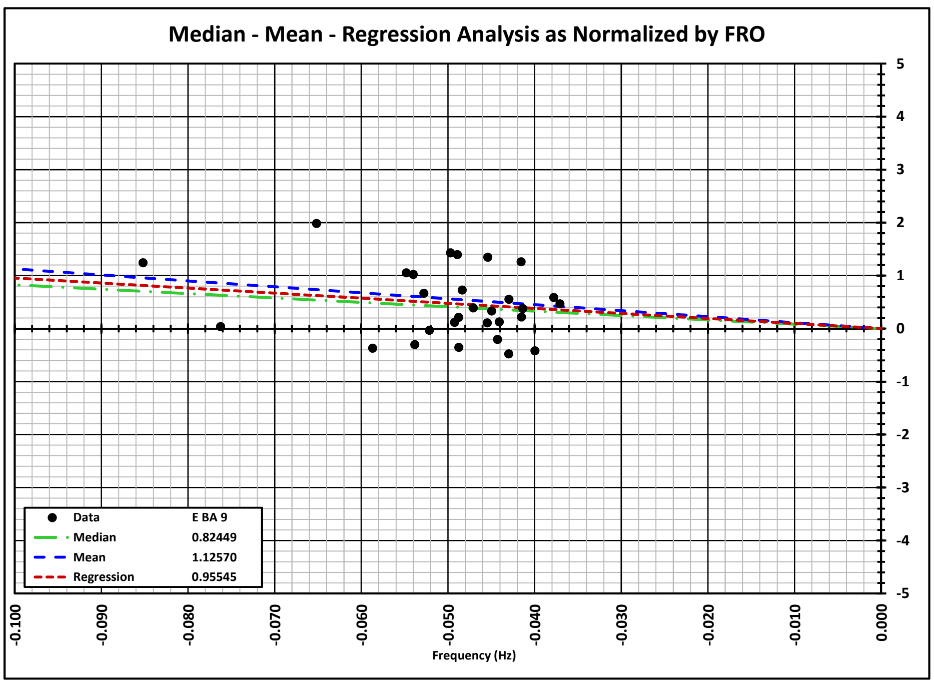
20
15
10
5
0
-5
-10
-15
-20
-25
Data E BA 7
Median 0.35407
Mean 1.74493
Regression 1.03098
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
5
4
3
2
1
0
-1
-2
-3
-4
-5
Data E BA 7
Median 0.35407
Mean 1.74493
Regression 1.03098
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 8
Median 0.45946
Mean 1.01731
Regression 0.76053
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 9
Median 0.82449
Mean 1.12570
Regression 0.95545
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4
3
2
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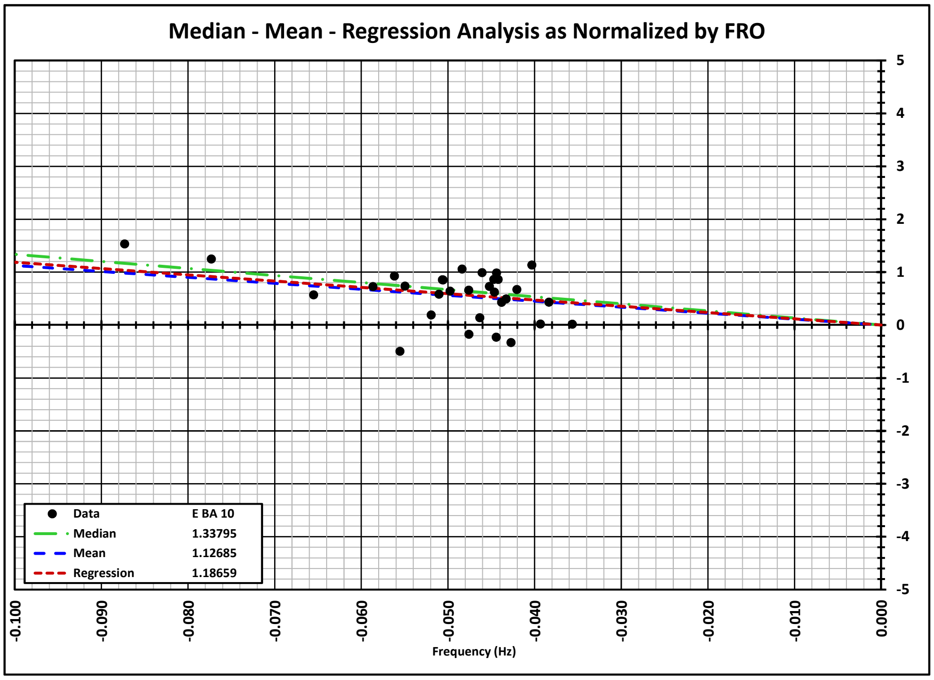
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 10
Median 1.33795
Mean 1.12685
Regression 1.18659
Frequency (Hz)
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-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
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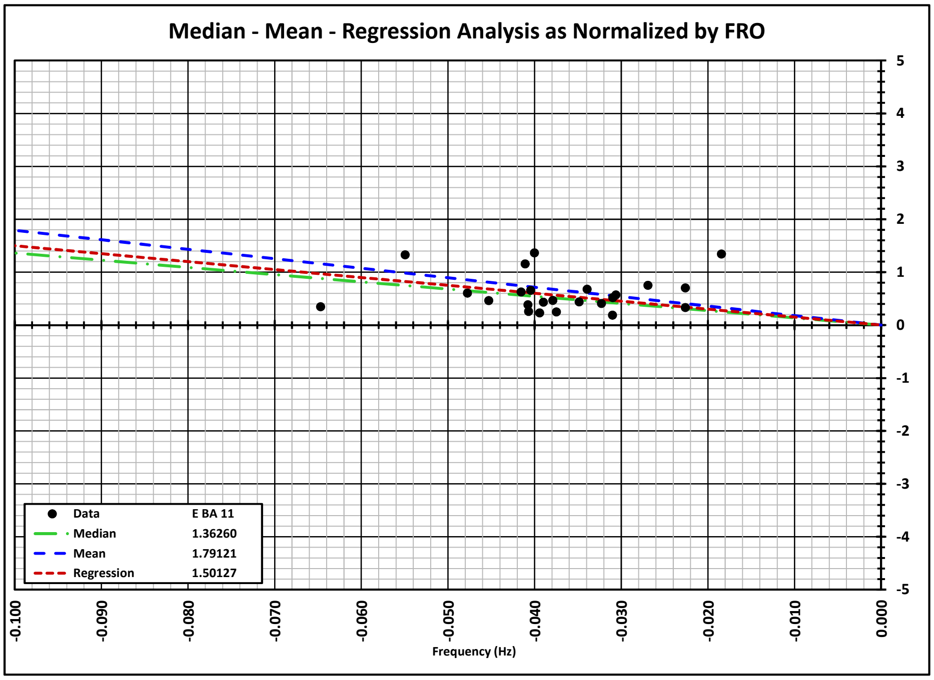
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 11
Median 1.36260
Mean 1.79121
Regression 1.50127
Frequency (Hz)
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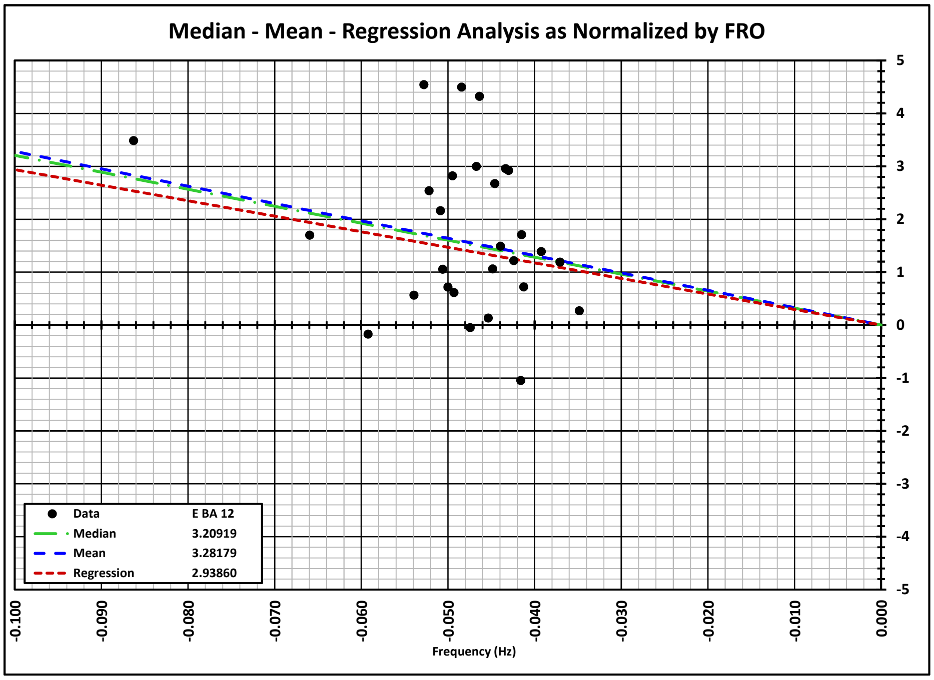
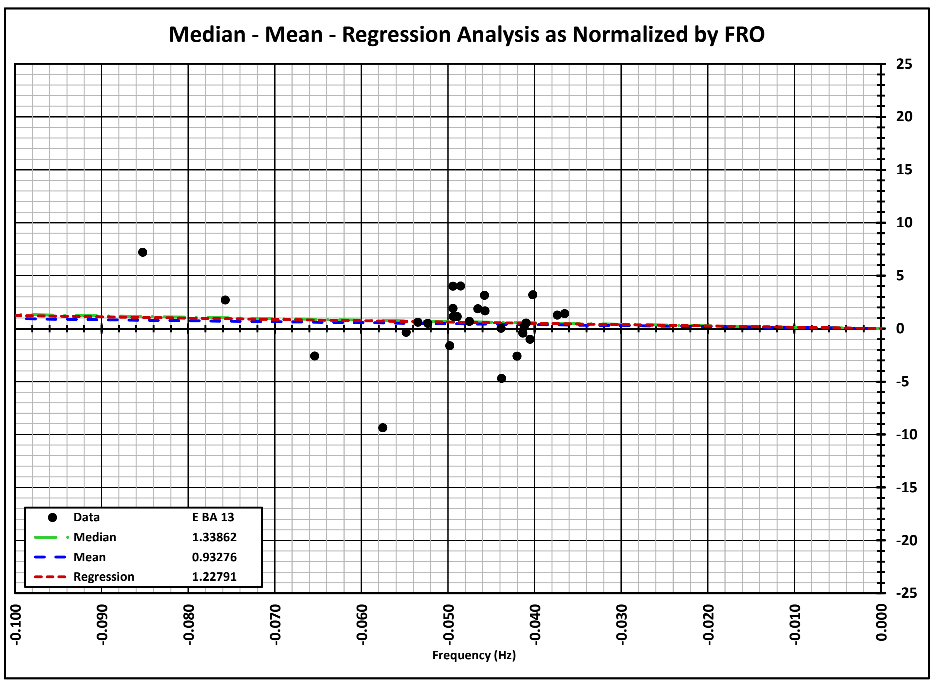
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 12
Median 3.20919
Mean 3.28179
Regression 2.93860
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 13
Median 1.33862
Mean 0.93276
Regression 1.22791
Frequency (Hz)
25
20
15
10
5
0
-5
-10
-15
-20
-25
-0.100
-0.090
-0.080
-0.070
-0.060
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-0.040
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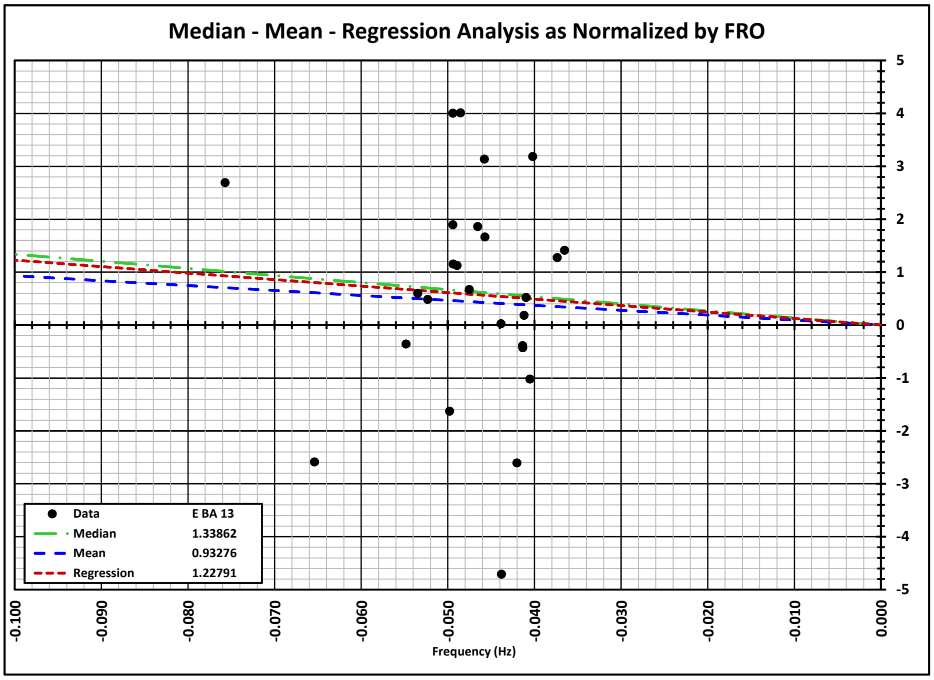
0.000


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 13
Median 1.33862
Mean 0.93276
Regression 1.22791
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
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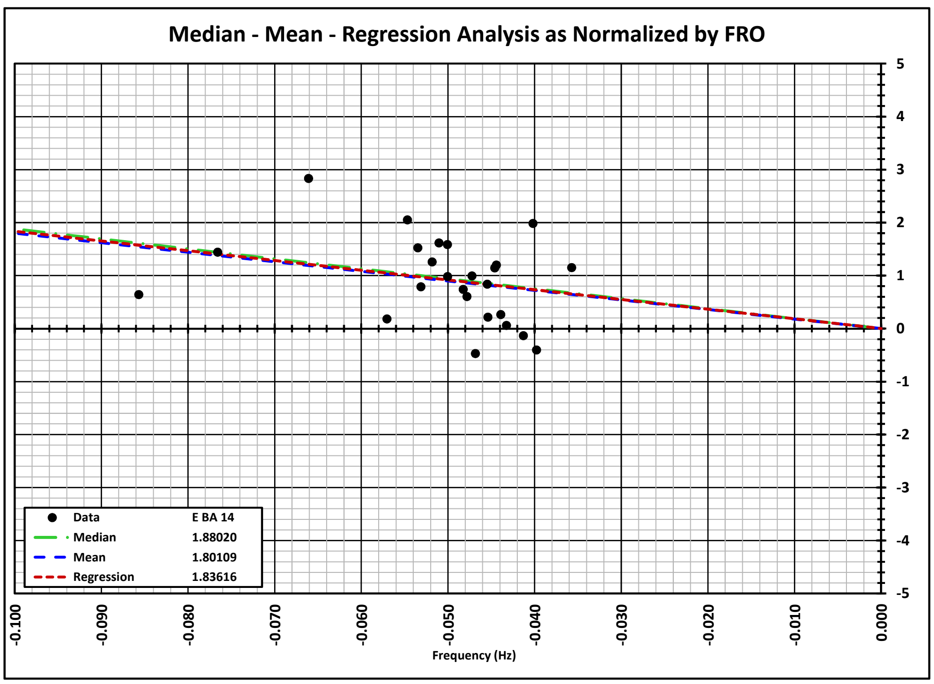
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 14
Median 1.88020
Mean 1.80109
Regression 1.83616
Frequency (Hz)
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-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
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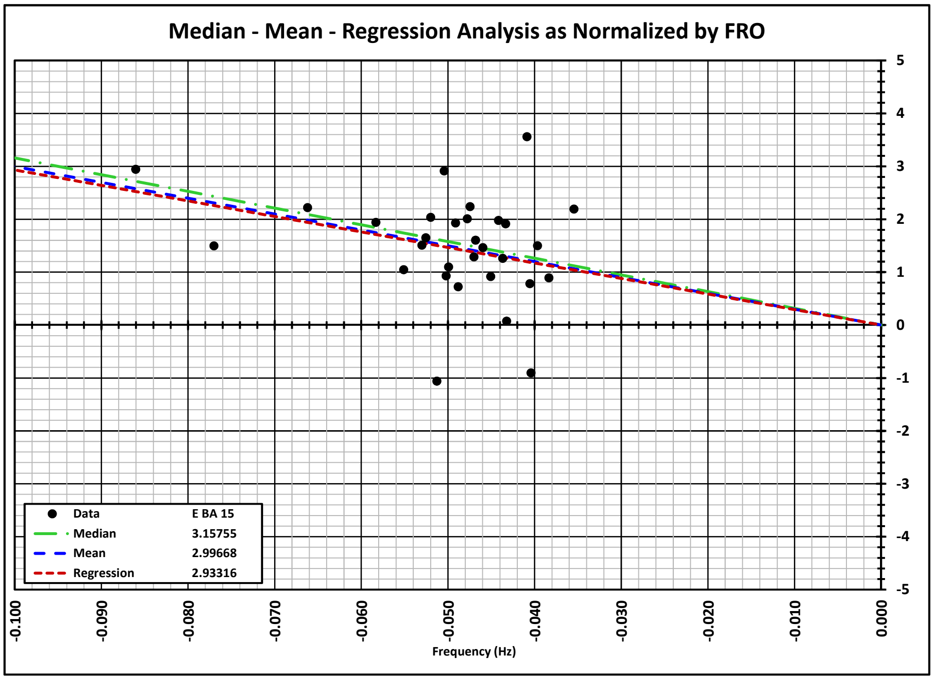
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 15
Median 3.15755
Mean 2.99668
Regression 2.93316
Frequency (Hz)
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-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
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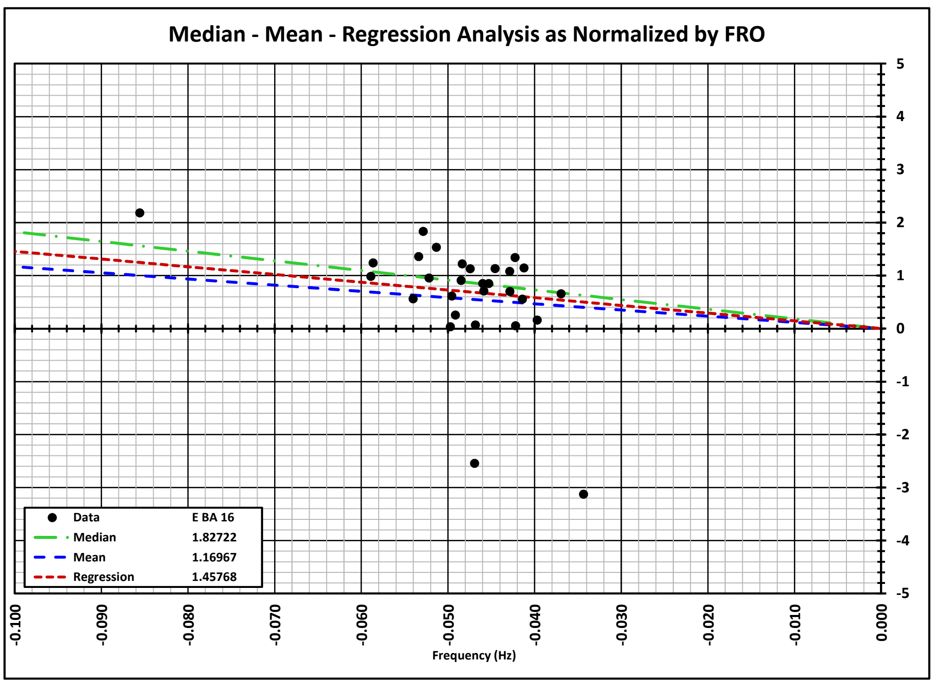
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 16
Median 1.82722
Mean 1.16967
Regression 1.45768
Frequency (Hz)
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-0.080
-0.070
-0.060
-0.050
-0.040
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0
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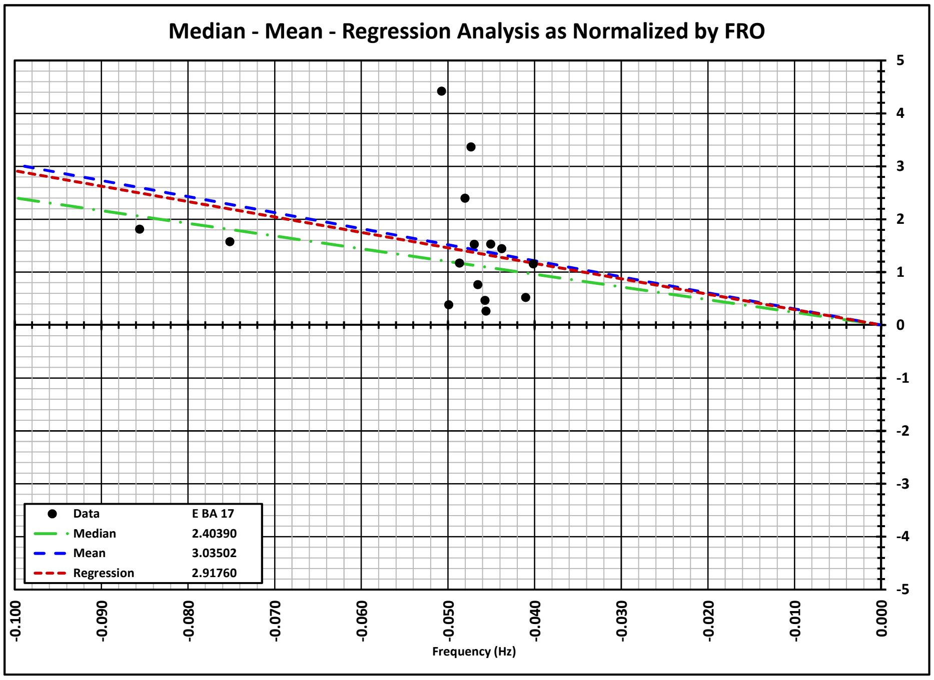
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
5
4
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2
1
0
-1
-2
-3
-4
-5
Data E BA 17
Median 2.40390
Mean 3.03502
Regression 2.91760
-0.100
-0.090
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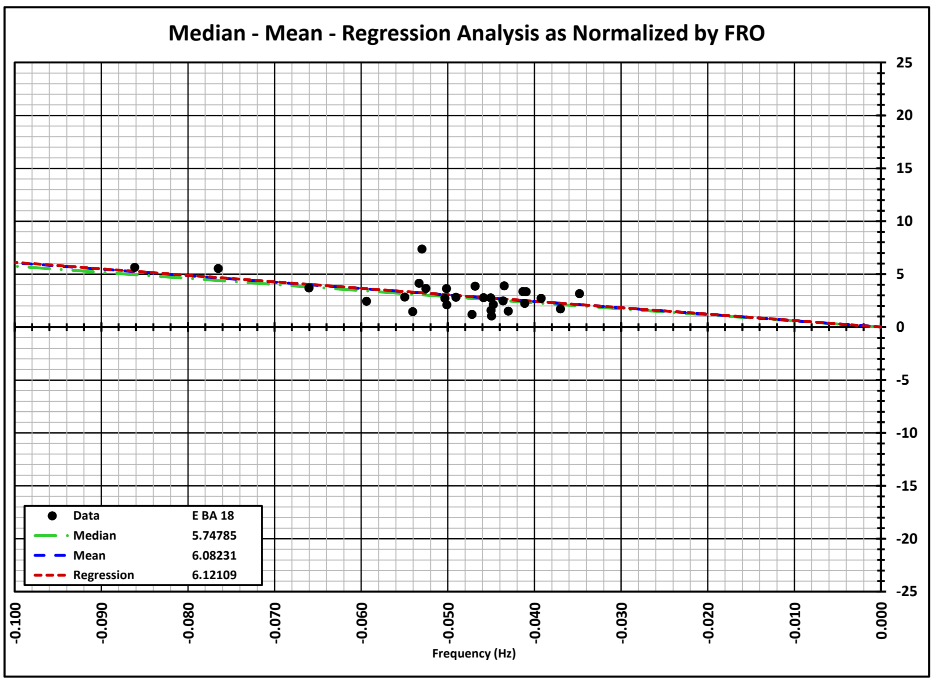
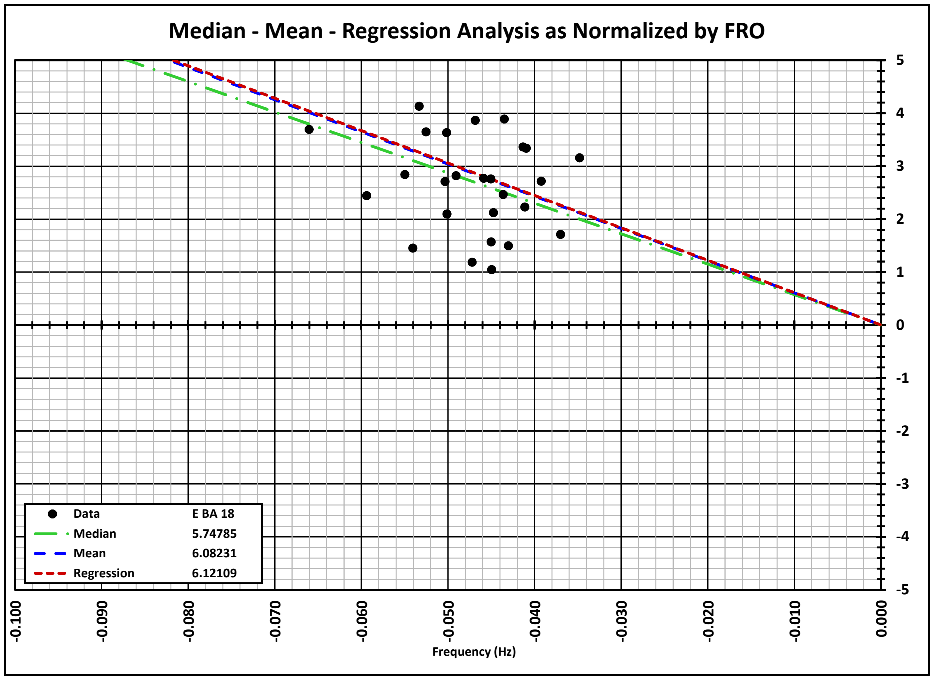
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
25
20
15
10
5
0
-5
-10
-15
-20
-25
Data E BA 18
Median 5.74785
Mean 6.08231
Regression 6.12109
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 18
Median 5.74785
Mean 6.08231
Regression 6.12109
Frequency (Hz)
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
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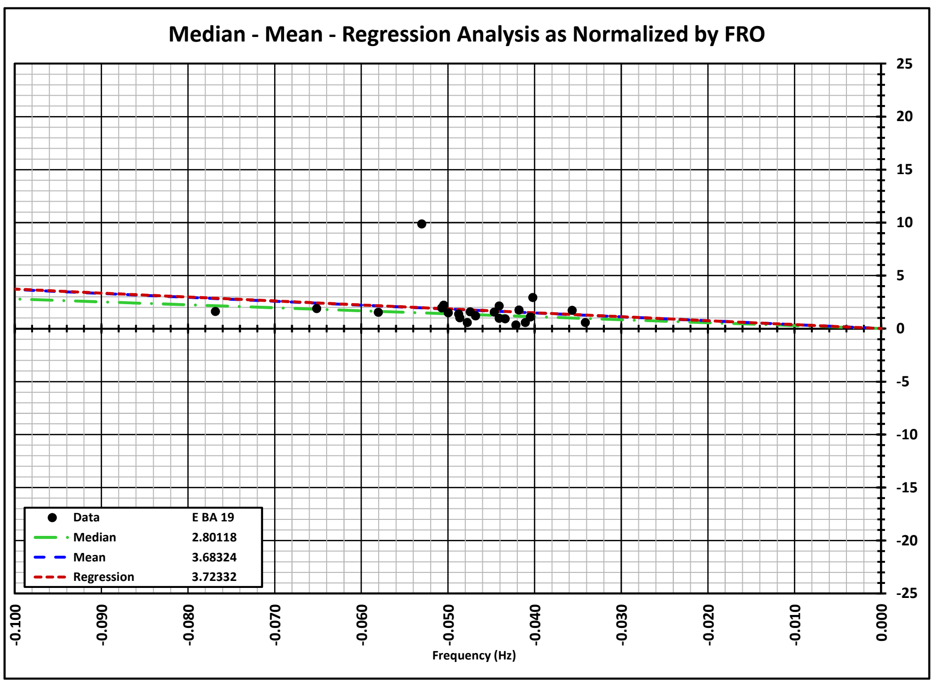
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 19
Median 2.80118
Mean 3.68324
Regression 3.72332
Frequency (Hz)
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-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
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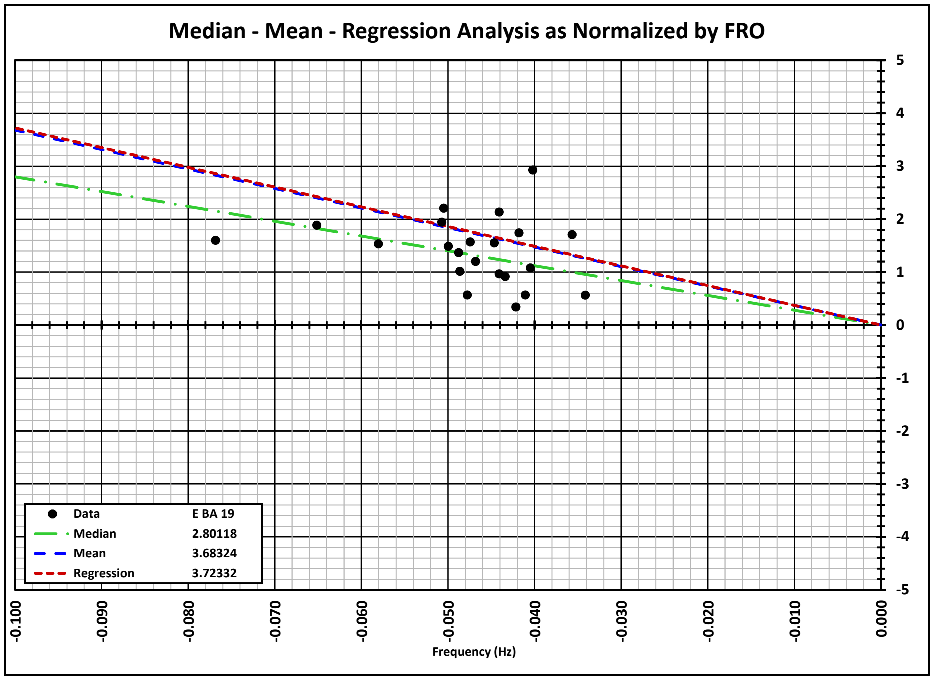
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 19
Median 2.80118
Mean 3.68324
Regression 3.72332
Frequency (Hz)
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1
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-1
-2
-3
-4
-5
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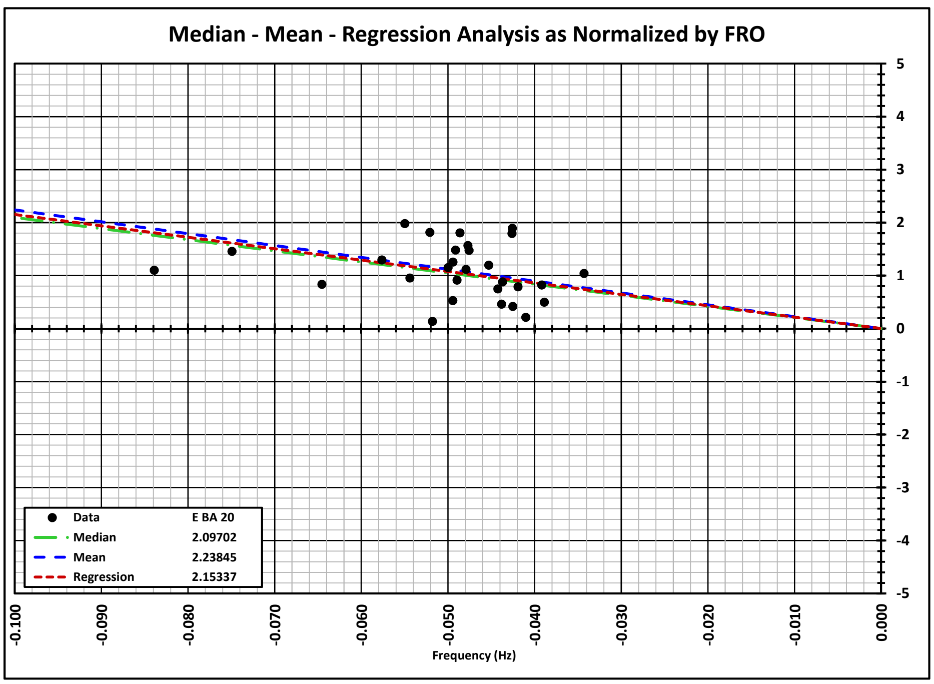
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 20
Median 2.09702
Mean 2.23845
Regression 2.15337
Frequency (Hz)
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-5
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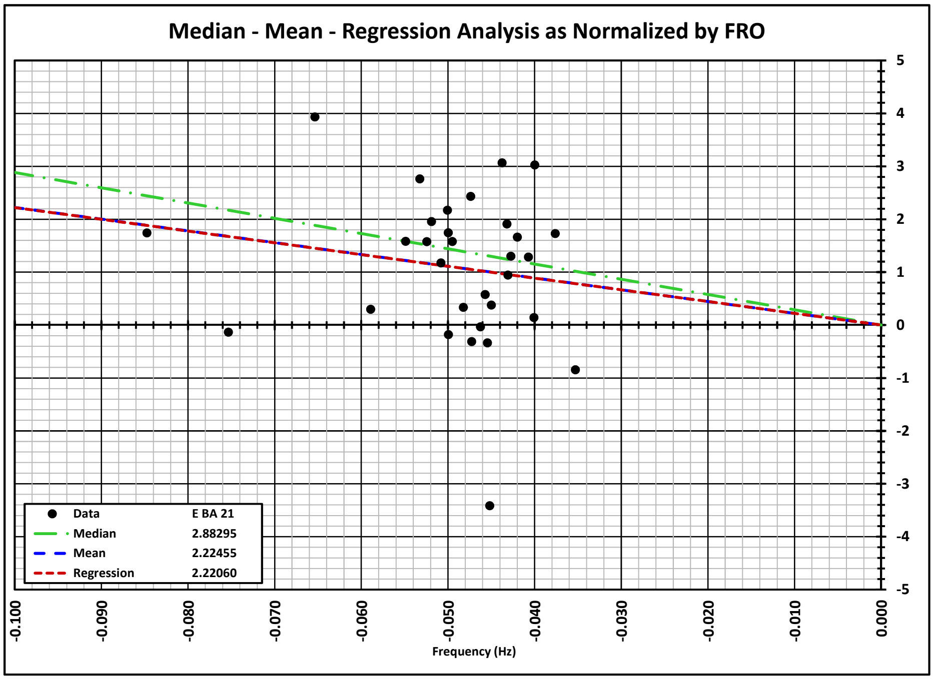
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 21
Median 2.88295
Mean 2.22455
Regression 2.22060
Frequency (Hz)
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-5
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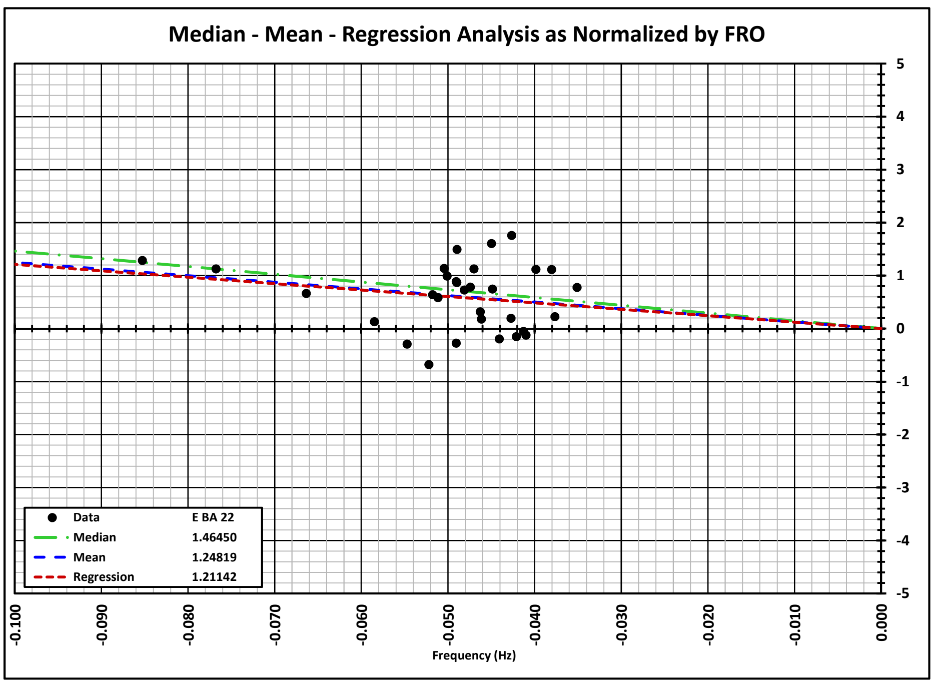
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 22
Median 1.46450
Mean 1.24819
Regression 1.21142
Frequency (Hz)
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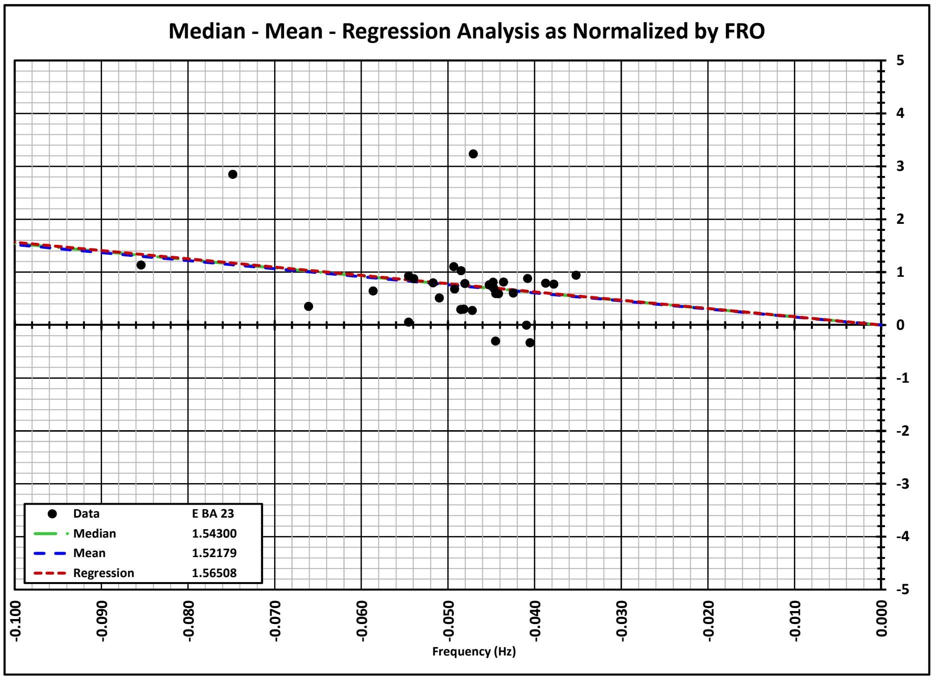
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 23
Median 1.54300
Mean 1.52179
Regression 1.56508
Frequency (Hz)
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-3
-4
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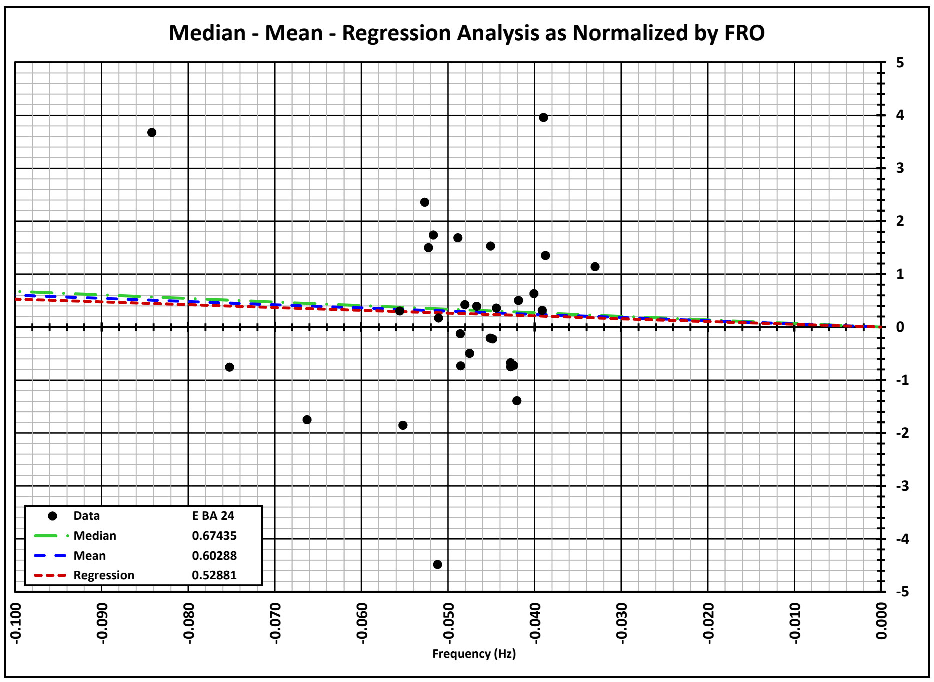
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 24
Median 0.67435
Mean 0.60288
Regression 0.52881
Frequency (Hz)
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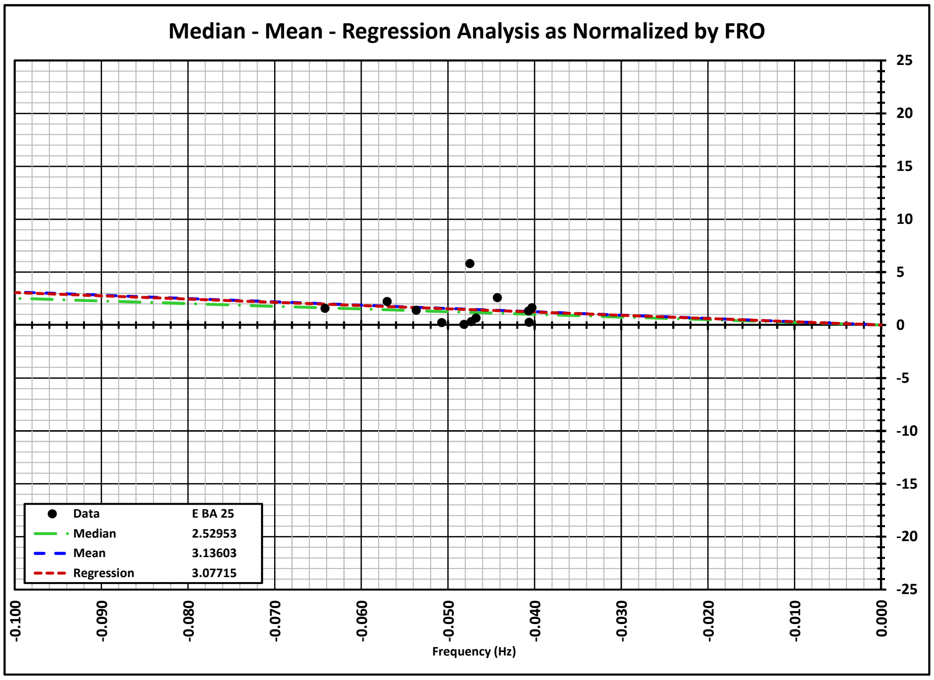
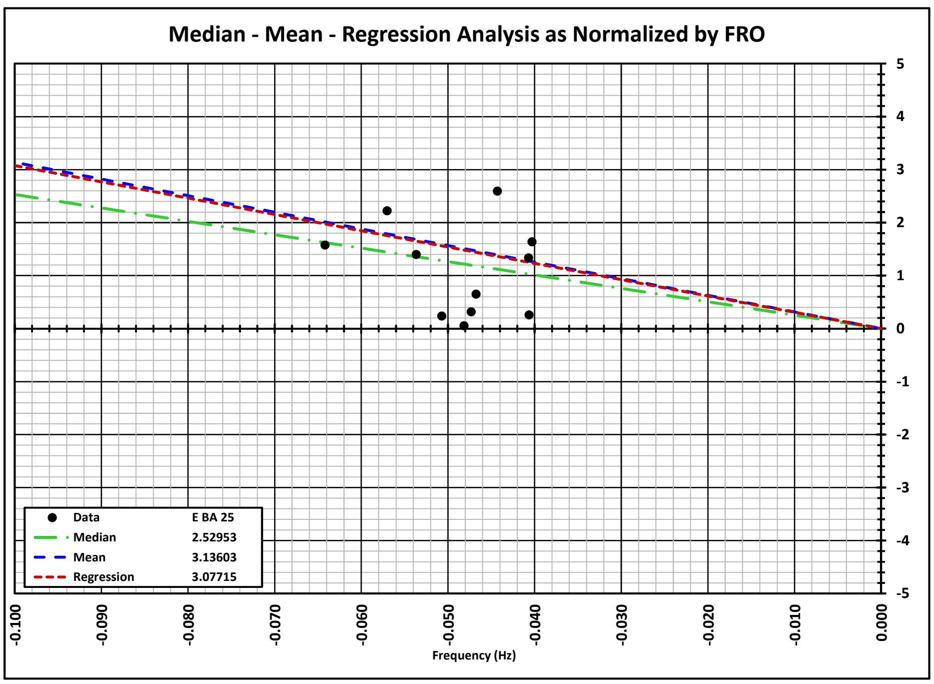
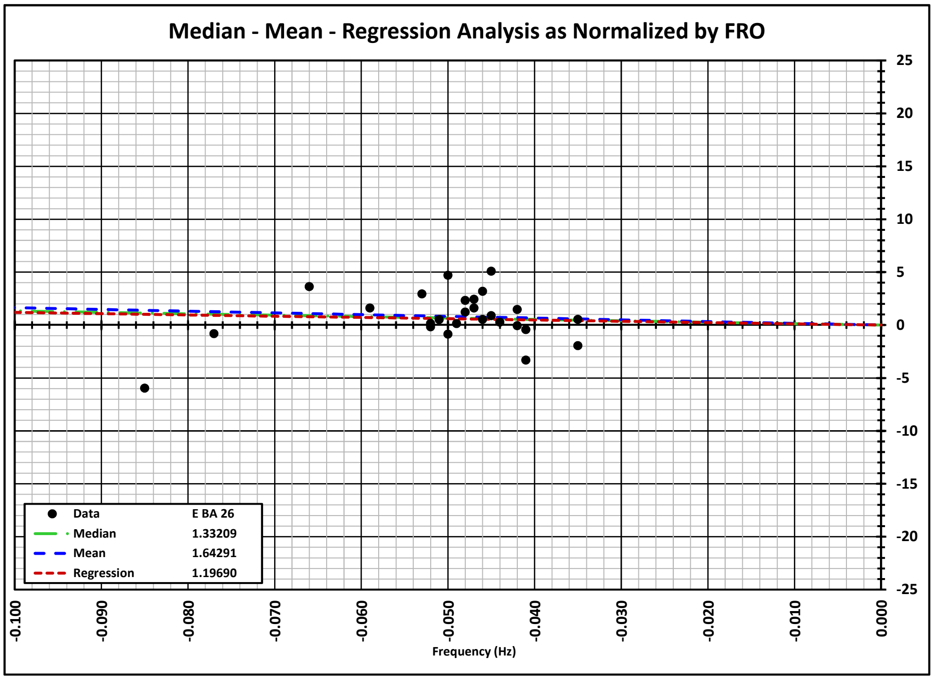
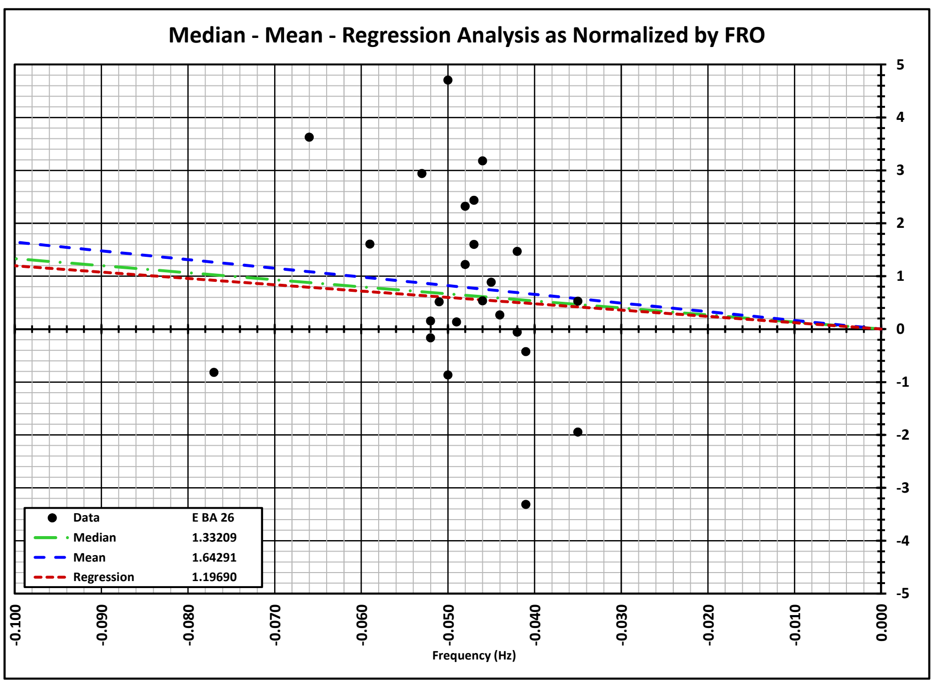
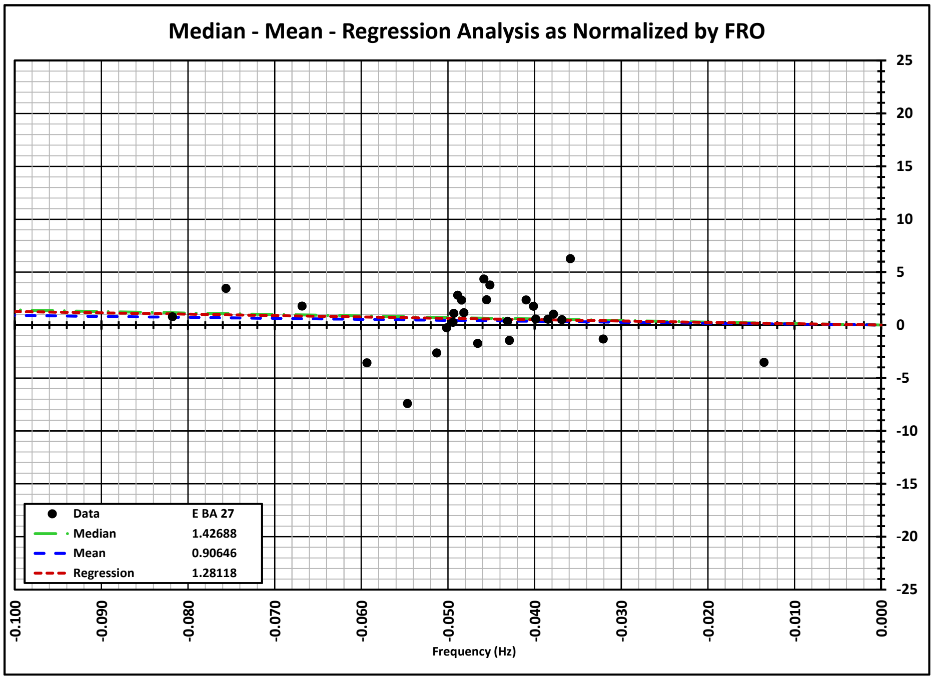
-4
-5

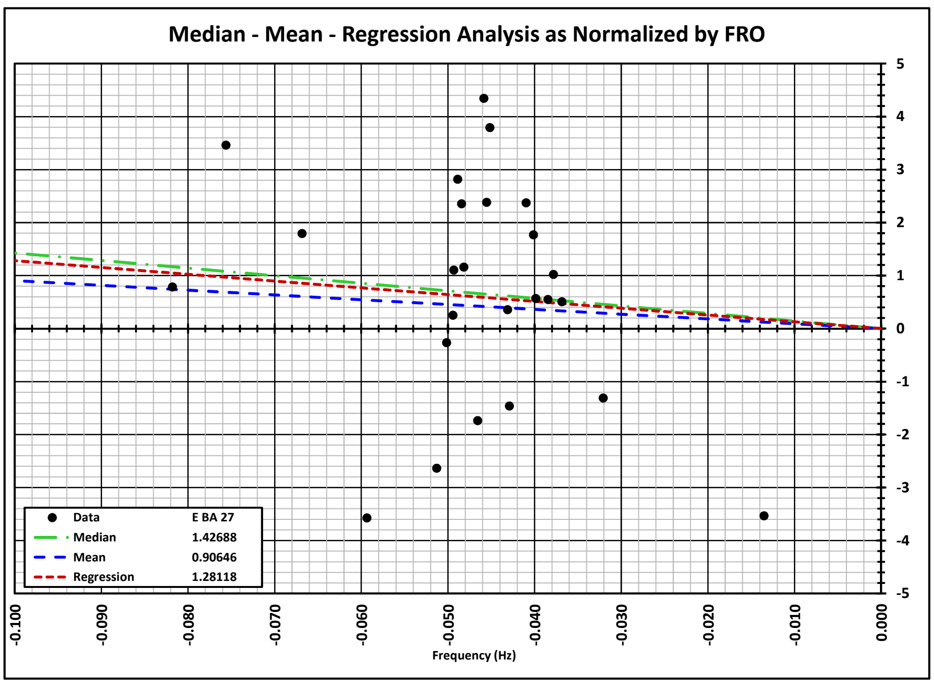

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 25
Median 2.52953
Mean 3.13603
Regression 3.07715
Frequency (Hz)

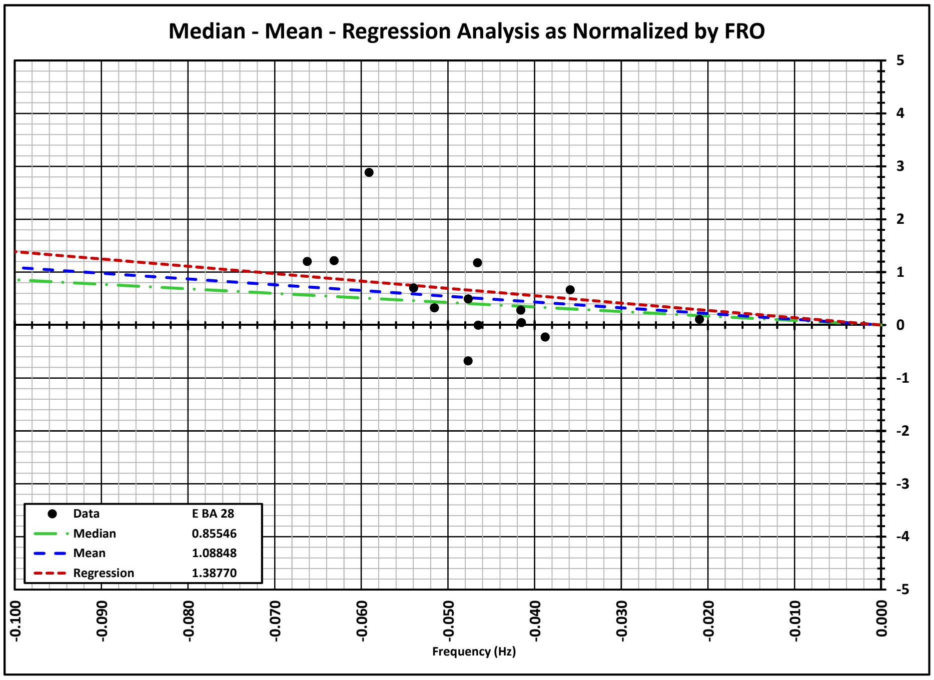

Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 25
Median 2.52953
Mean 3.13603
Regression 3.07715
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 26
Median 1.33209
Mean 1.64291
Regression 1.19690
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 26
Median 1.33209
Mean 1.64291
Regression 1.19690
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 27
Median
1.42688
Mean
0.90646
Regression
1.28118
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 27
Median
1.42688
Mean
0.90646
Regression
1.28118
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 28
Median 0.85546
Mean 1.08848
Regression 1.38770
Frequency (Hz)
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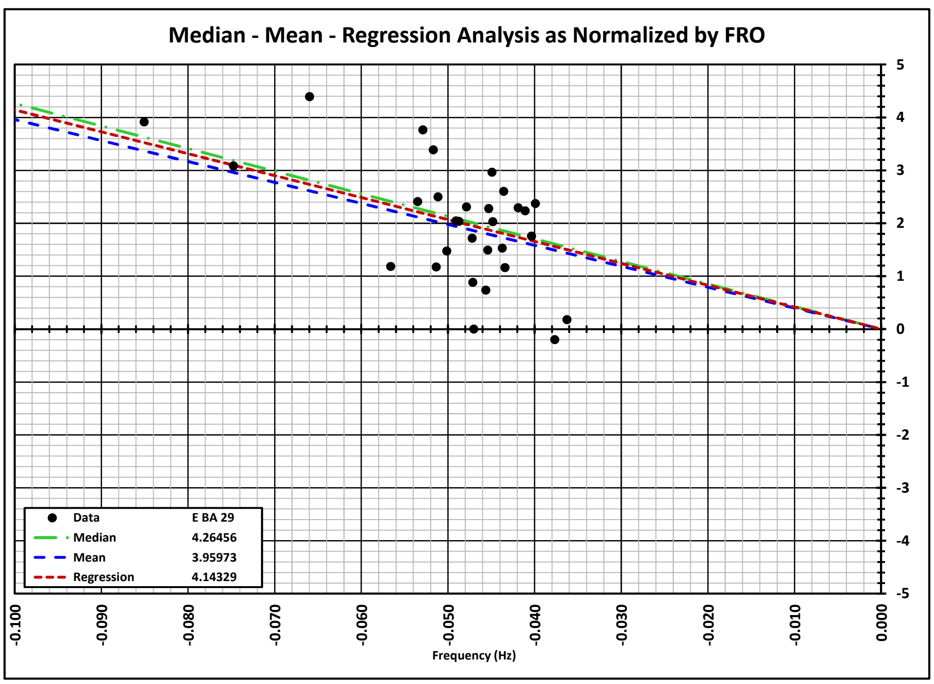
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 29
Median 4.26456
Mean 3.95973
Regression 4.14329
Frequency (Hz)
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-0.040
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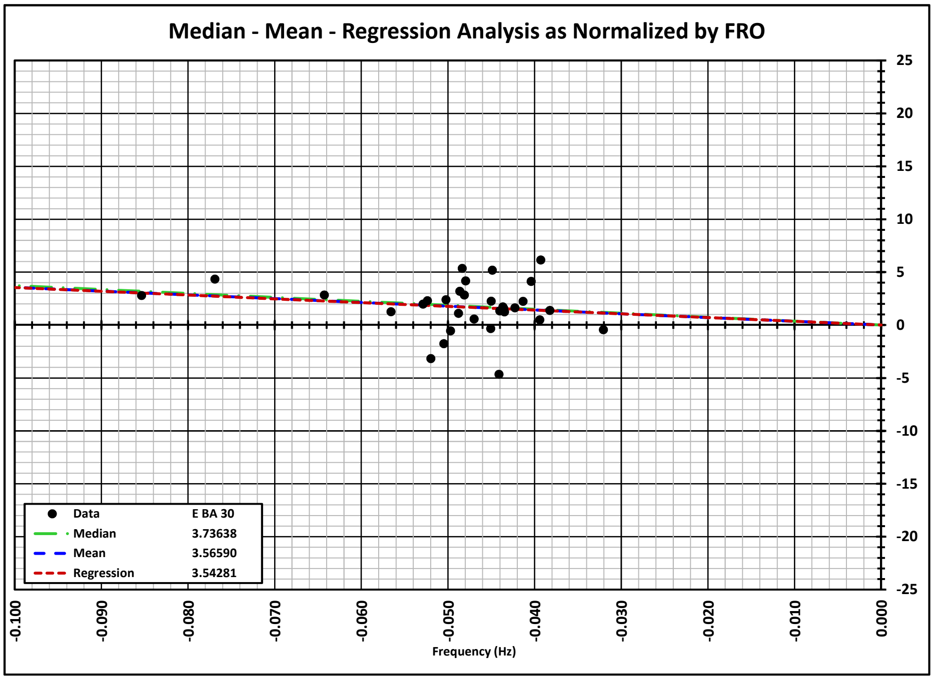
Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 30
Median 3.73638
Mean 3.56590
Regression 3.54281
25
20
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10
5
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-5
-10
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-0.100
-0.090
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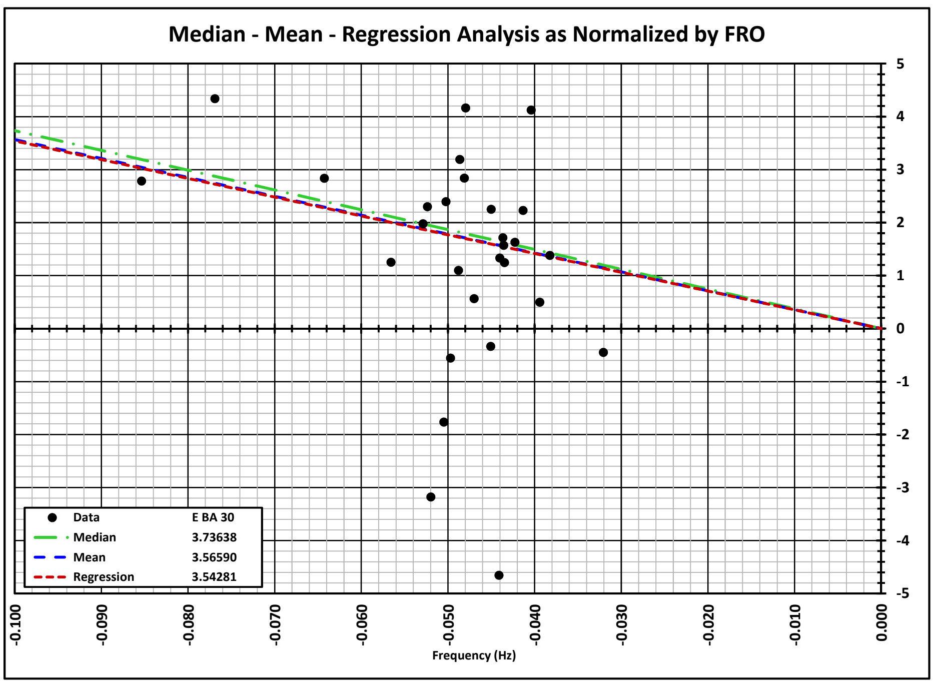
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data E BA 30
Median 3.73638
Mean 3.56590
Regression 3.54281
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-2
-3
-4
-5
-0.100
-0.090
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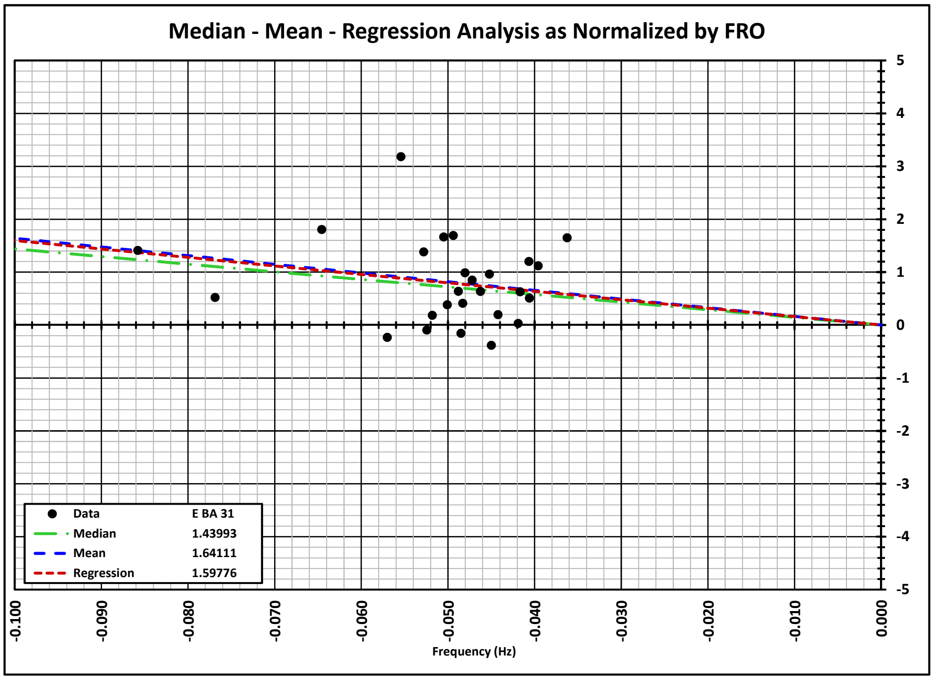
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data
E BA 31
Median
1.43993
Mean
1.64111
Regression
1.59776
Frequency (Hz)
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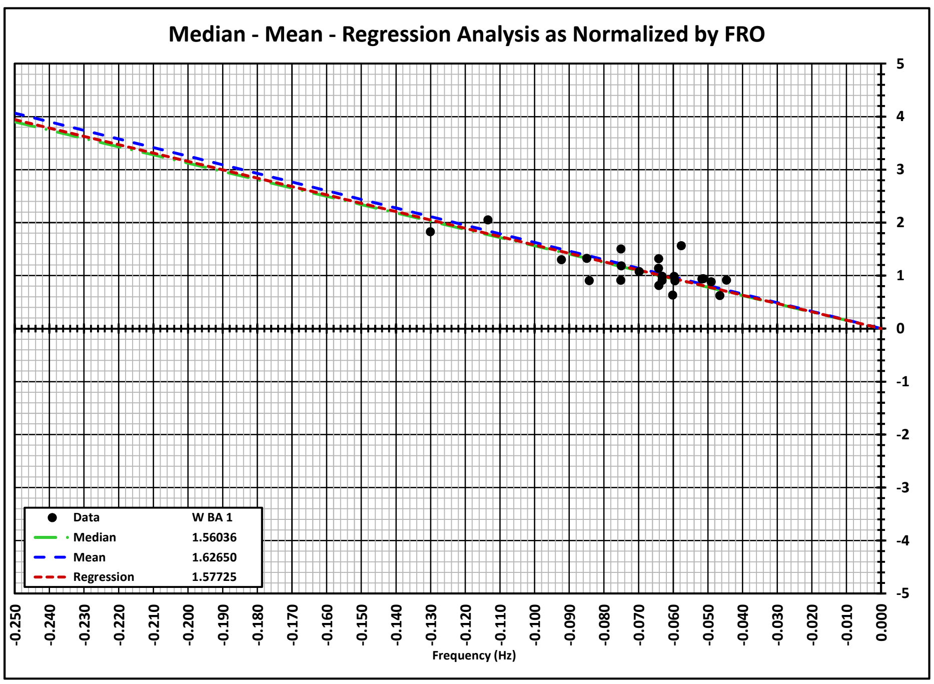
Median - Mean - Regression Analysis as Normalized by FRO
Data
W BA 1
Median
1.56036
Mean
1.62650
Regression
1.57725
Frequency (Hz)
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-0.220
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-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
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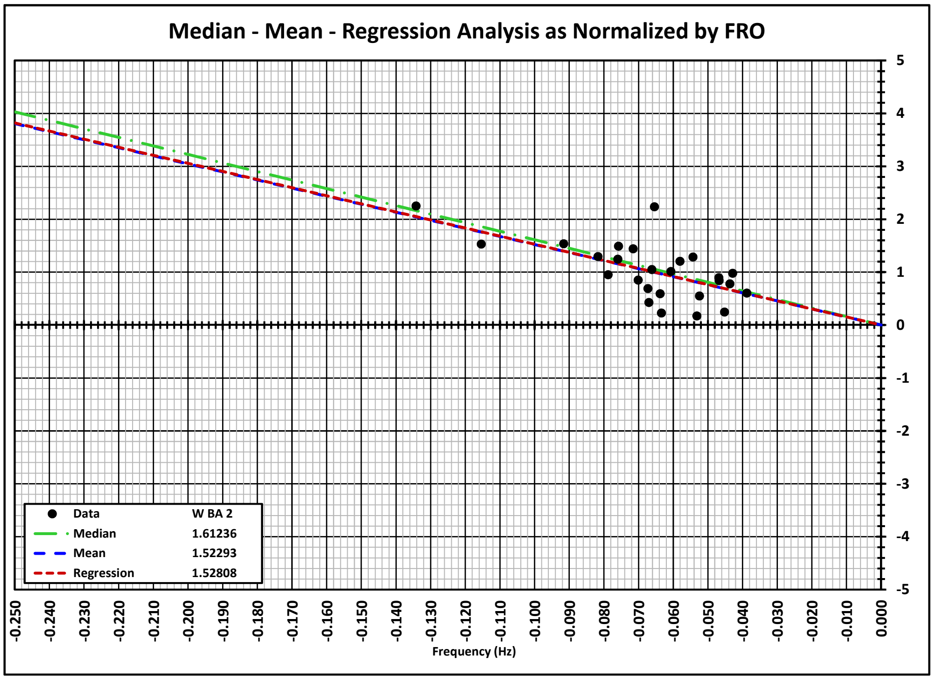
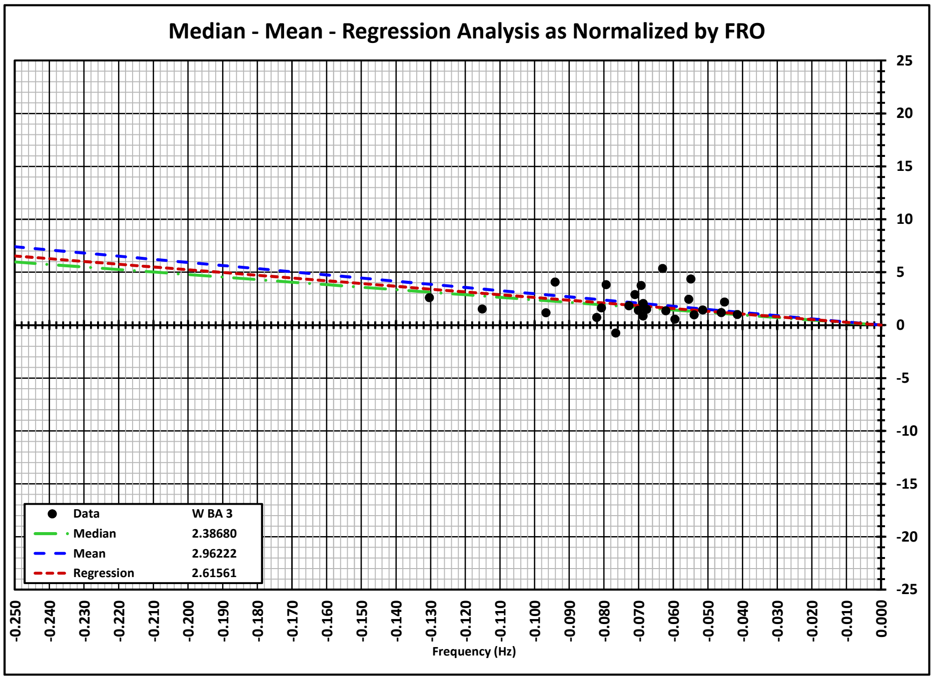
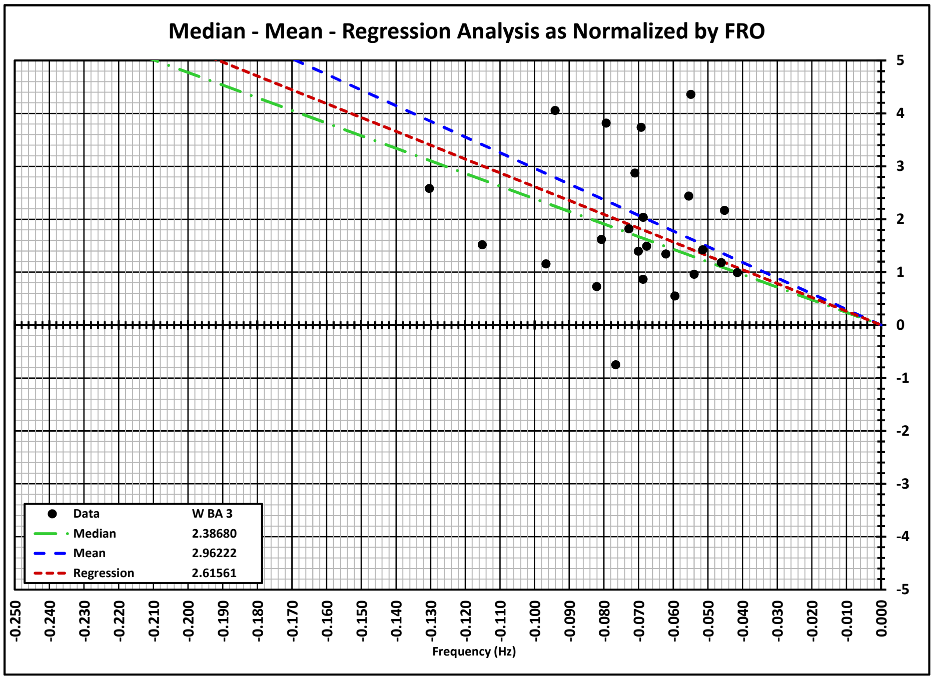
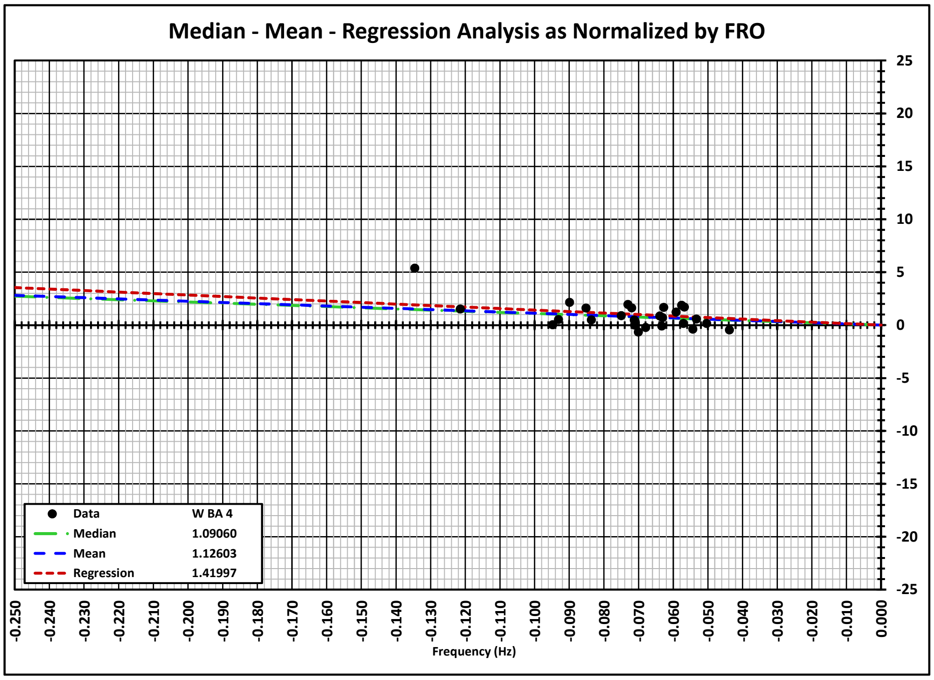
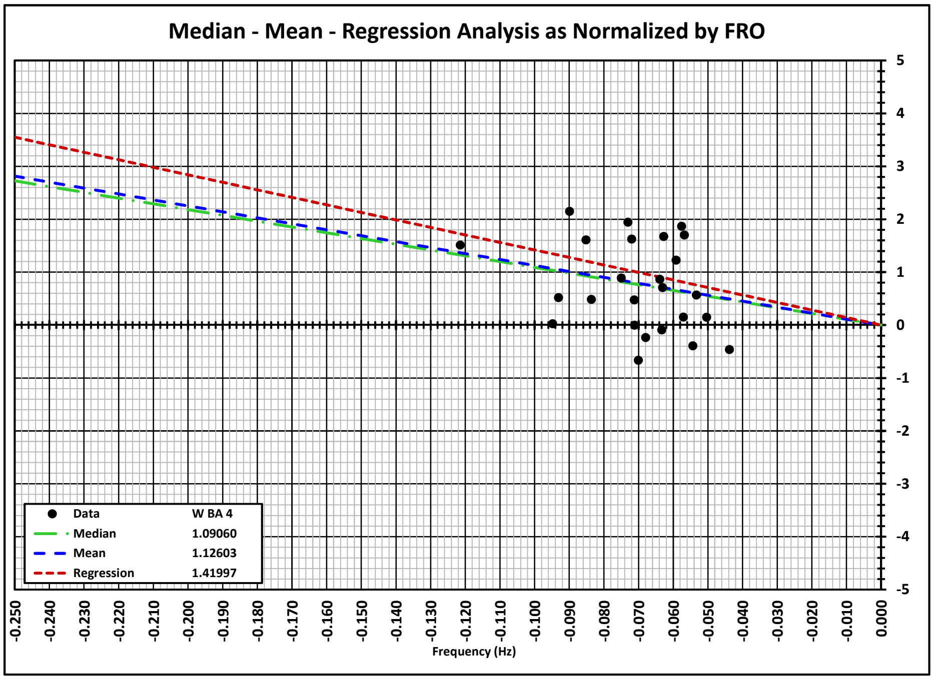
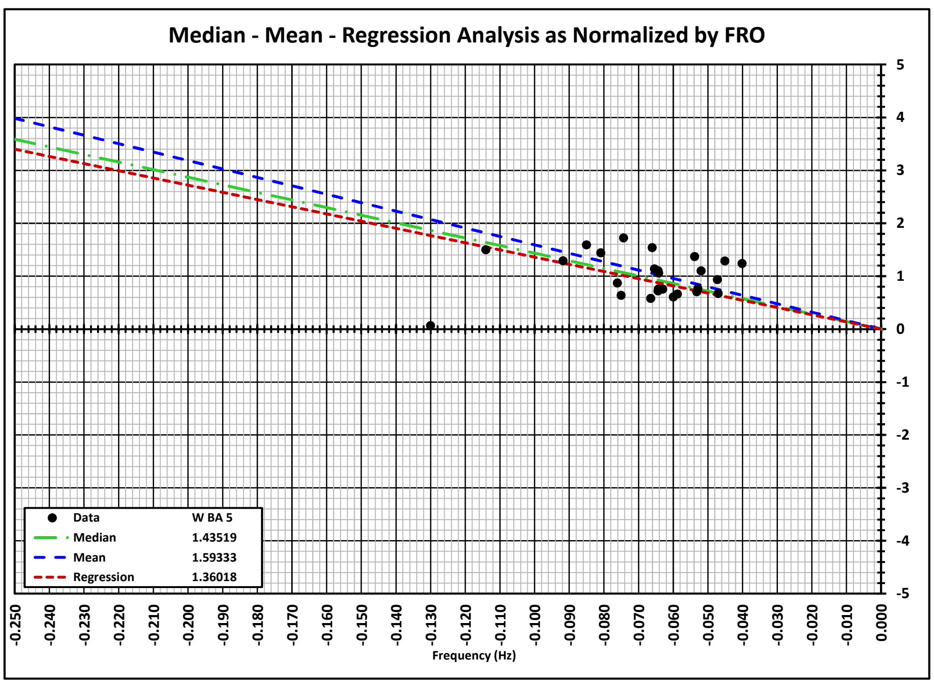

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 2
Median 1.61236
Mean 1.52293
Regression 1.52808
Frequency (Hz)

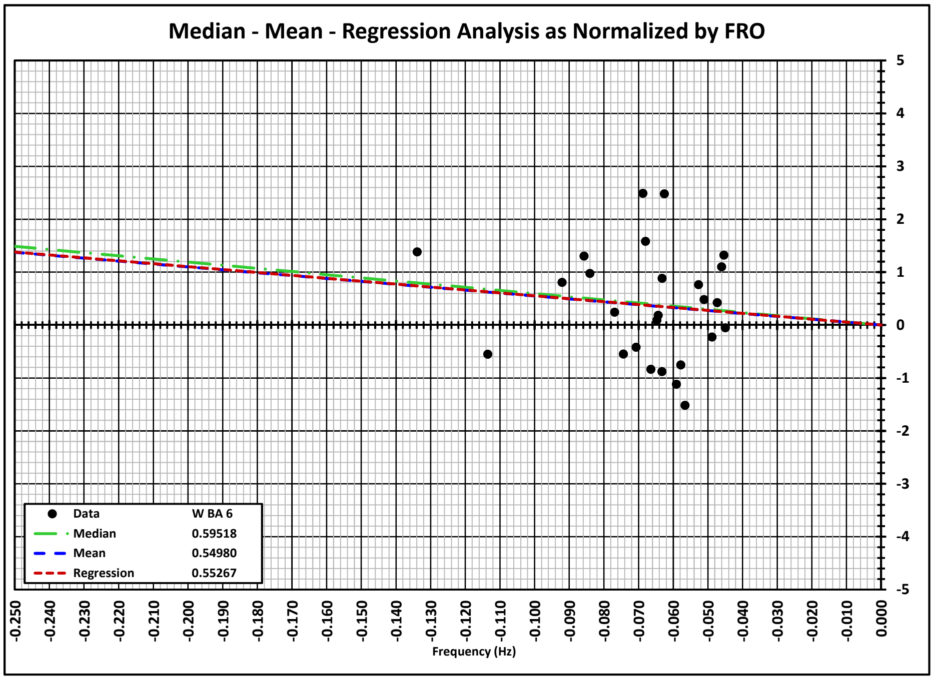

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 3
Median 2.38680
Mean 2.96222
Regression 2.61561
Frequency (Hz)

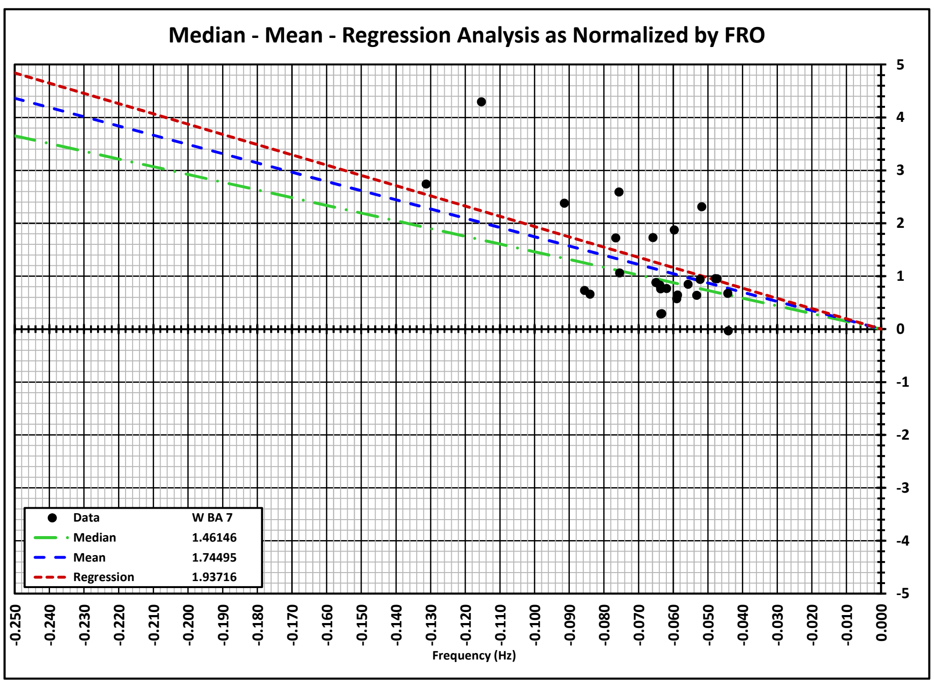

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 3
Median 2.38680
Mean 2.96222
Regression 2.61561
Frequency (Hz)

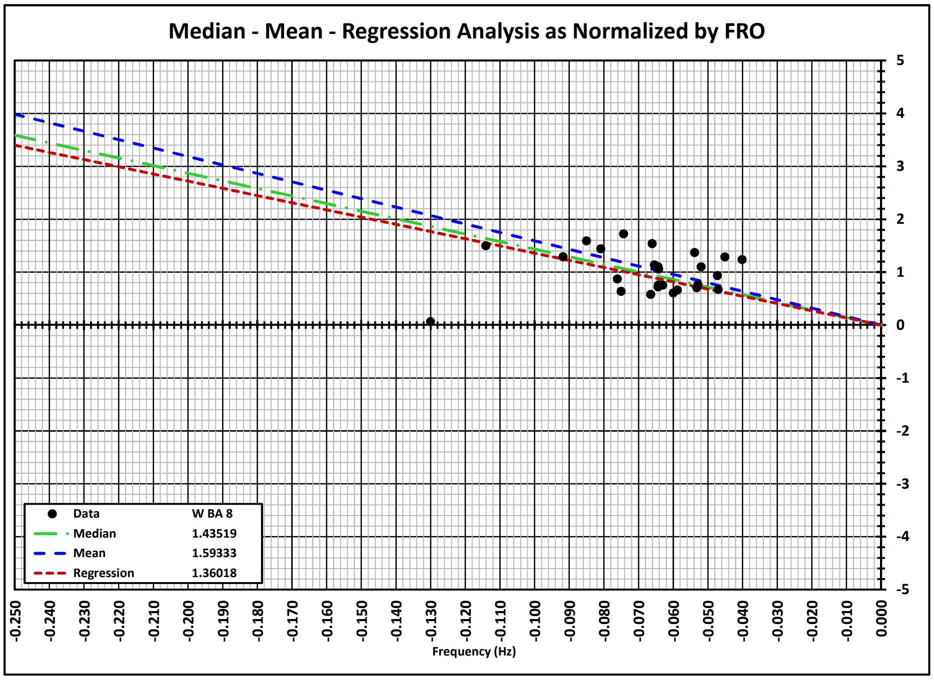

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 4
Median 1.09060
Mean 1.12603
Regression 1.41997
Frequency (Hz)

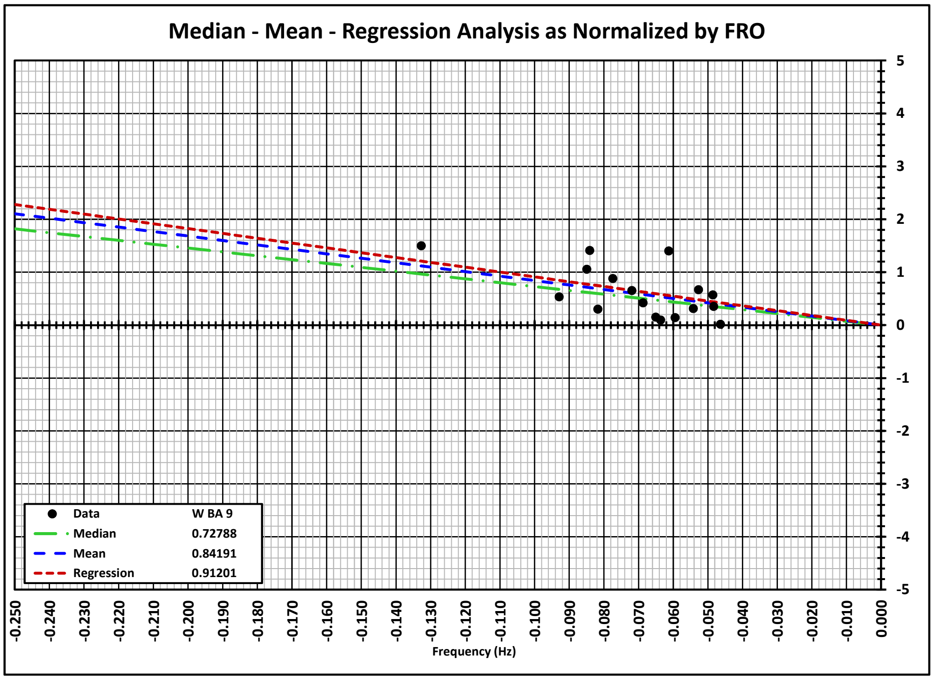

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 4
Median 1.09060
Mean 1.12603
Regression 1.41997
Frequency (Hz)

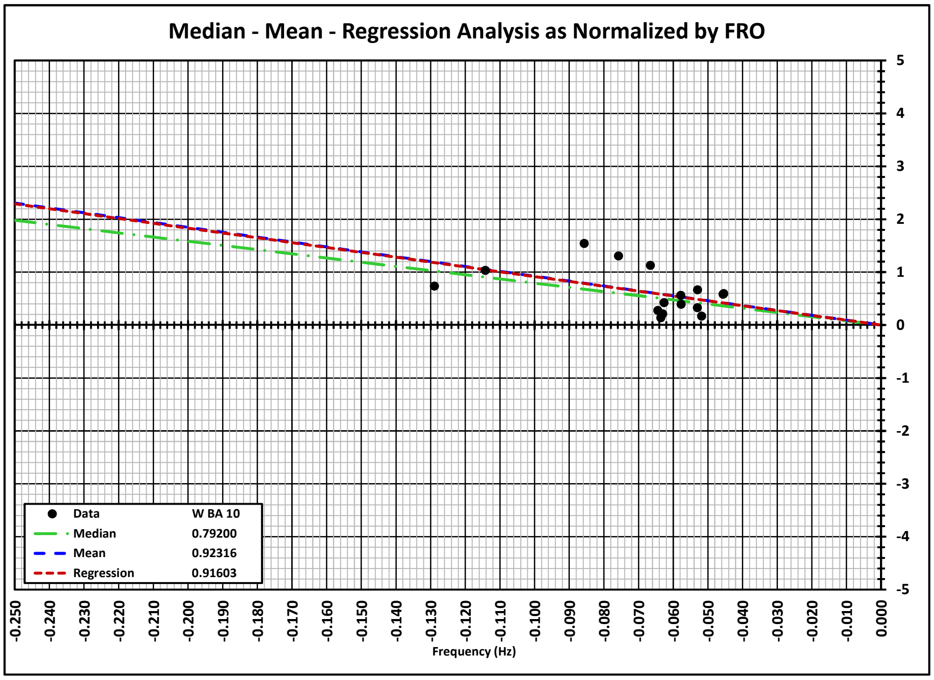

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 5
Median 1.43519
Mean 1.59333
Regression 1.36018
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 6
Median 0.59518
Mean 0.54980
Regression 0.55267
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 7
Median 1.46146
Mean 1.74495
Regression 1.93716
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 8
Median 1.43519
Mean 1.59333
Regression 1.36018
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 9
Median 0.72788
Mean 0.84191
Regression 0.91201
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 10
Median 0.79200
Mean 0.92316
Regression 0.91603
Frequency (Hz)
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-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
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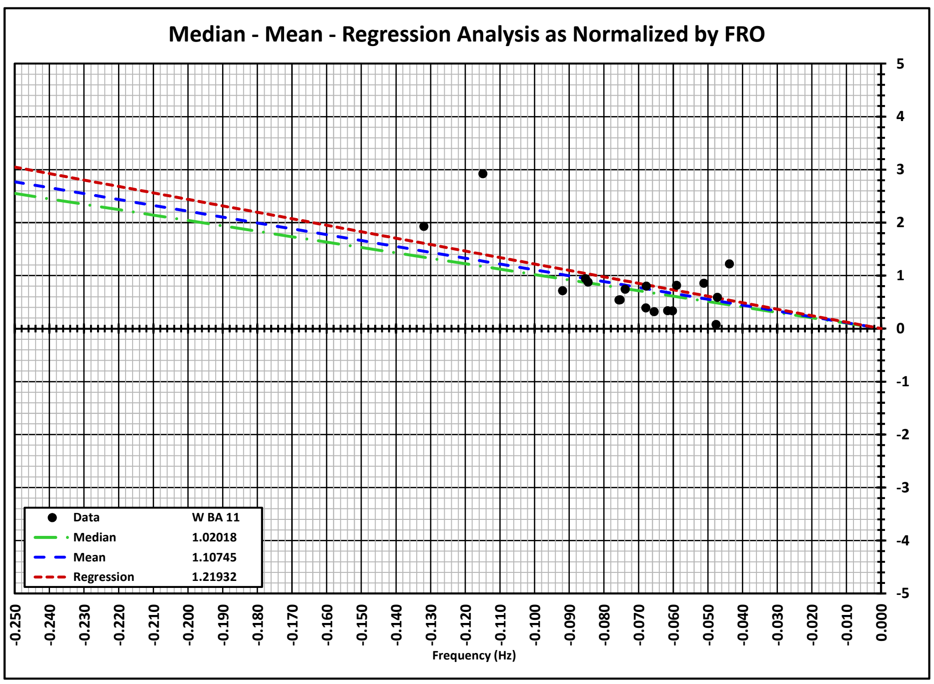
Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 11
Median 1.02018
Mean 1.10745
Regression 1.21932
Frequency (Hz)
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-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
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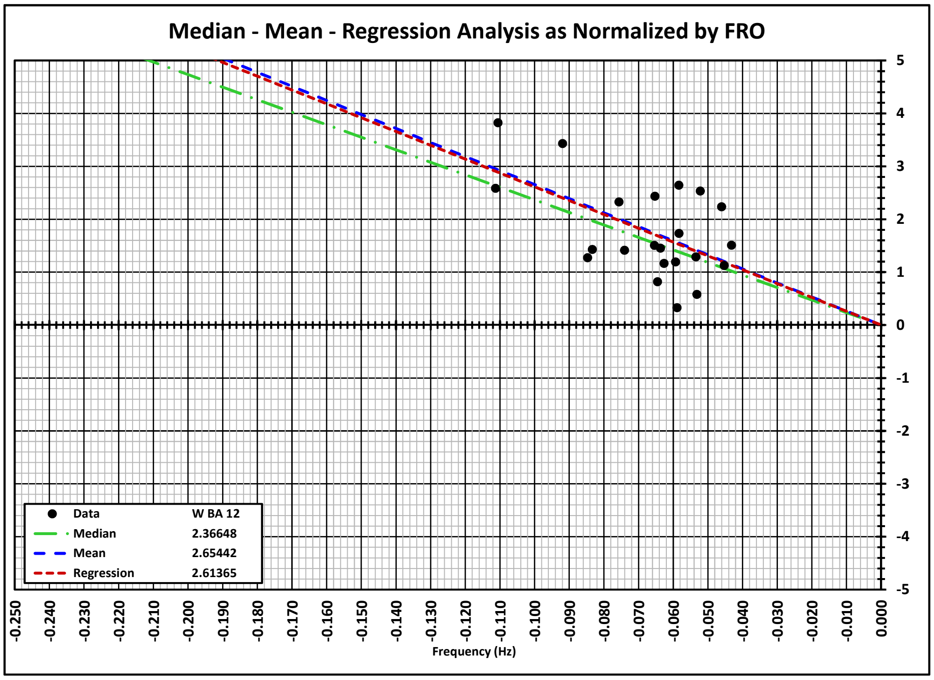
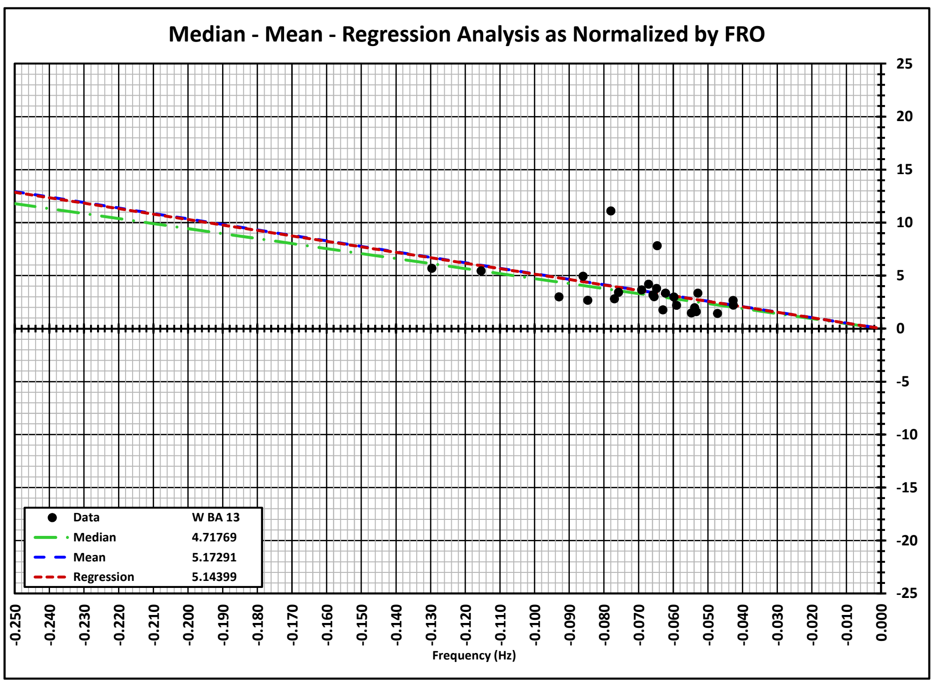
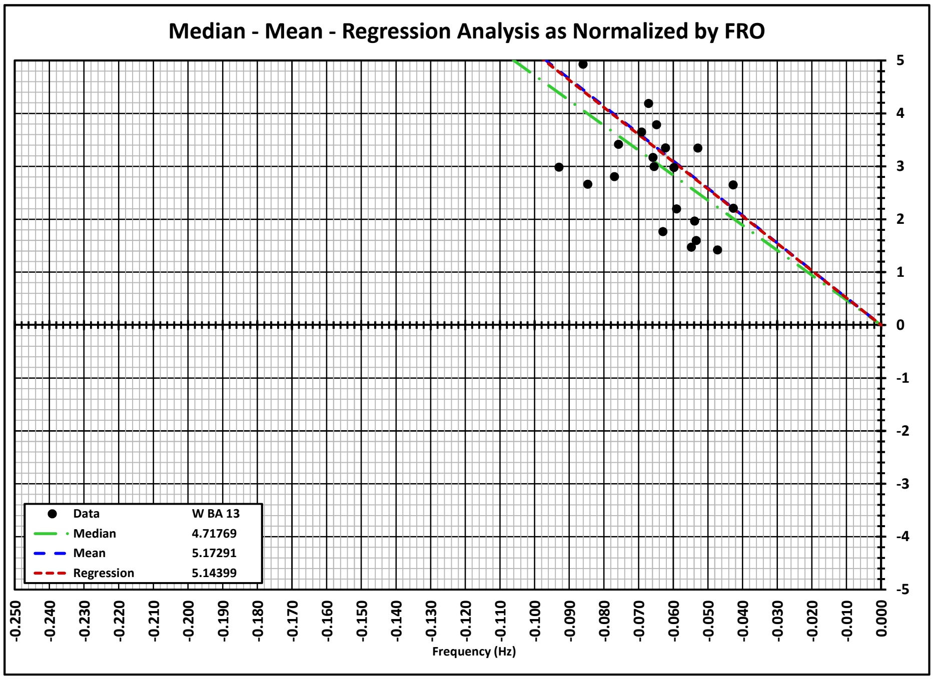
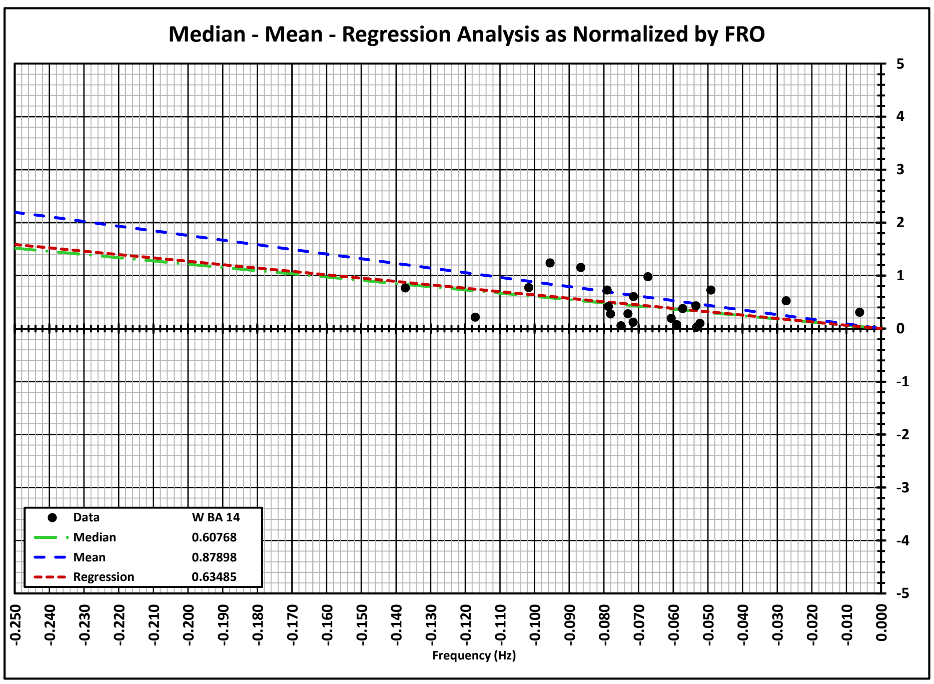
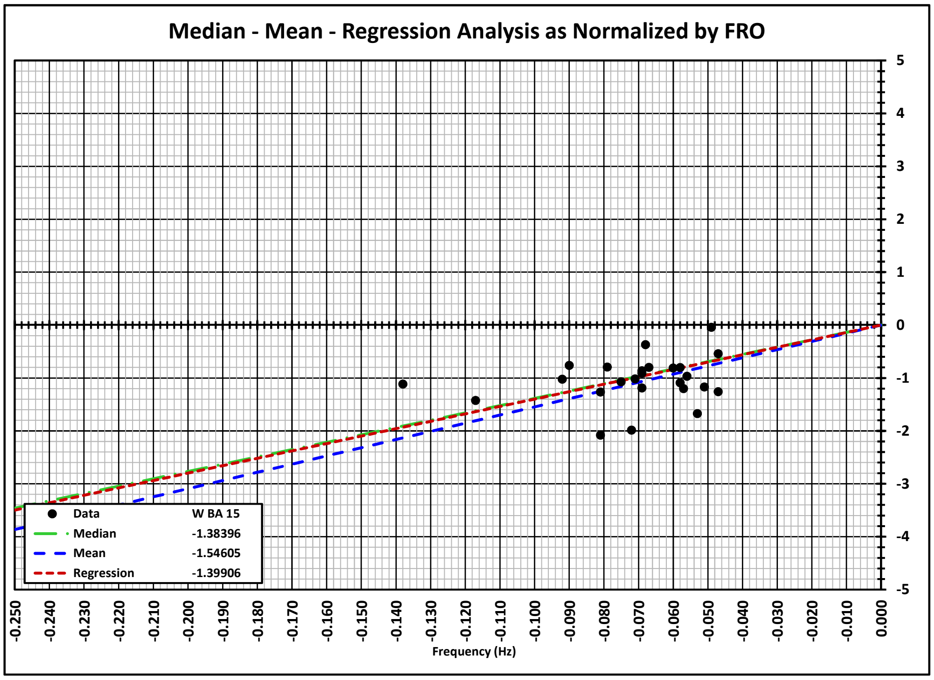
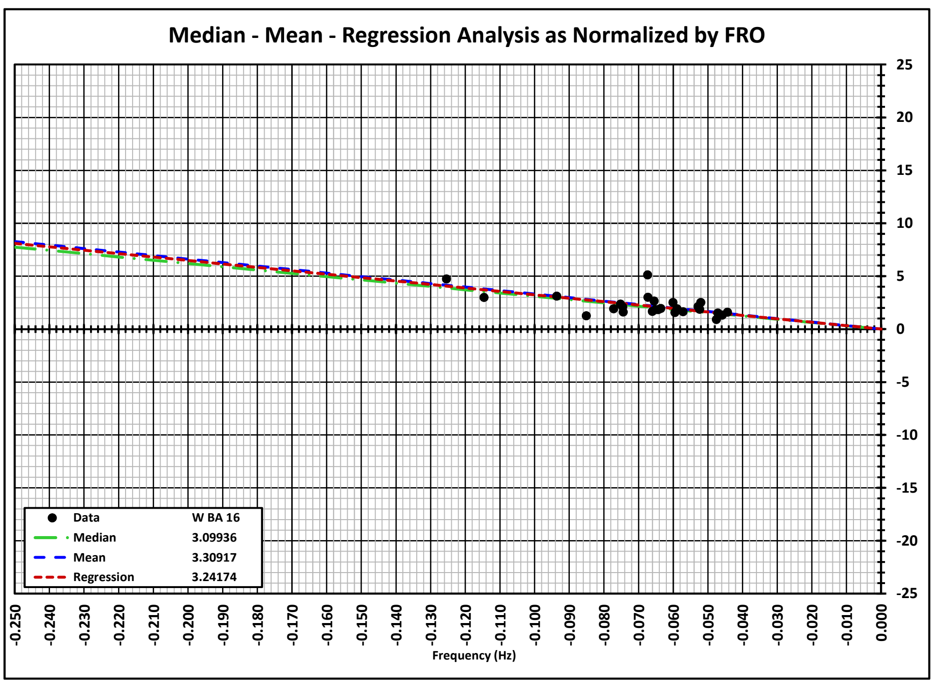

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 12
Median 2.36648
Mean 2.65442
Regression 2.61365
Frequency (Hz)

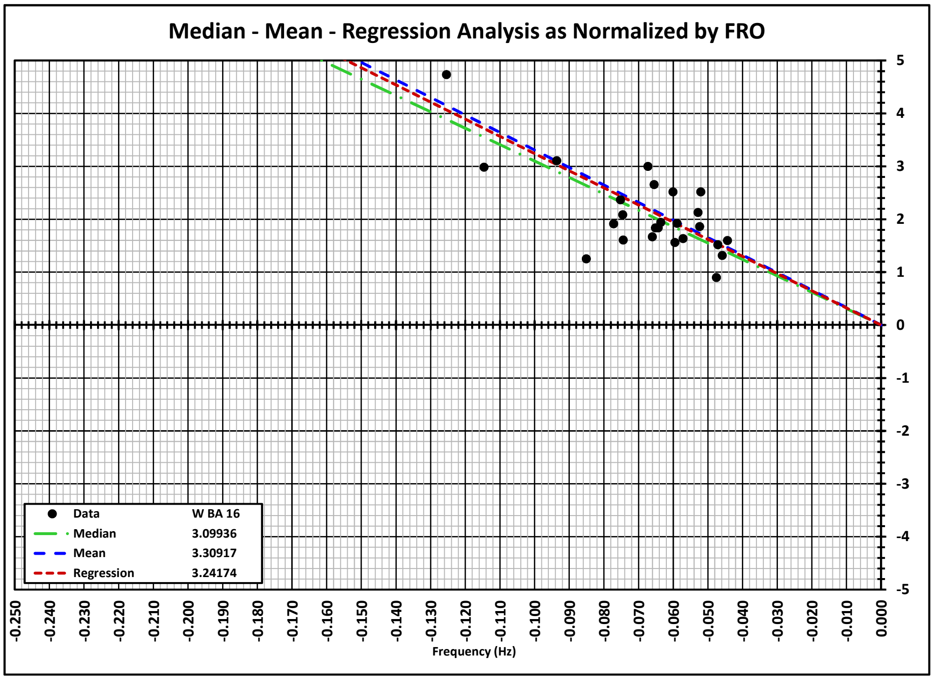

Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 13
Median 4.71769
Mean 5.17291
Regression 5.14399
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 13
Median 4.71769
Mean 5.17291
Regression 5.14399
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 14
Median 0.60768
Mean 0.87898
Regression 0.63485
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 15
Median -1.38396
Mean -1.54605
Regression -1.39906
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 16
Median 3.09936
Mean 3.30917
Regression 3.24174
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 16
Median 3.09936
Mean 3.30917
Regression 3.24174
Frequency (Hz)
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-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
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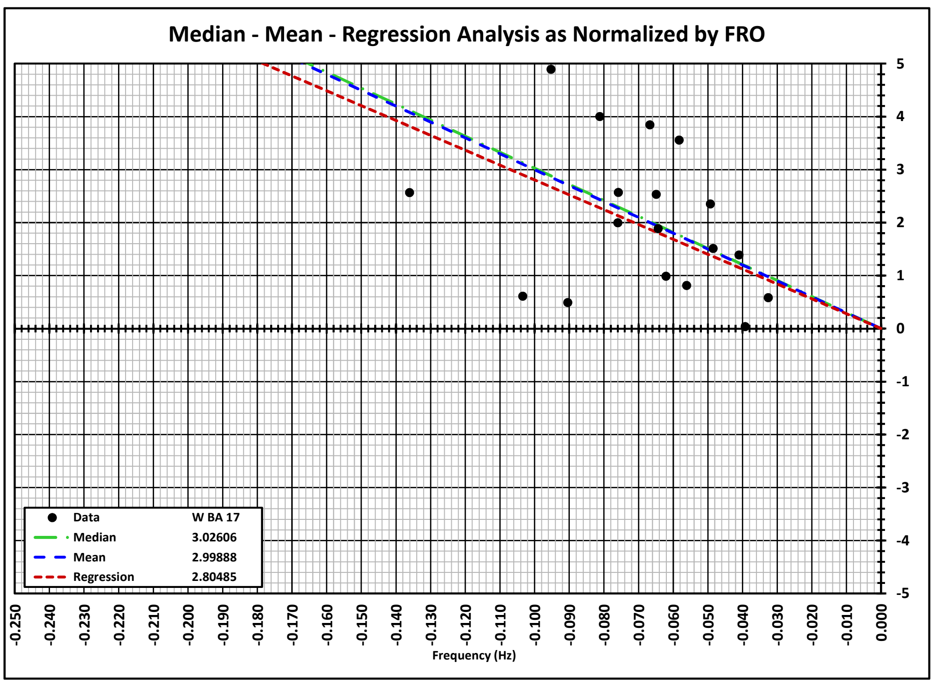
Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 17
Median 3.02606
Mean 2.99888
Regression 2.80485
Frequency (Hz)
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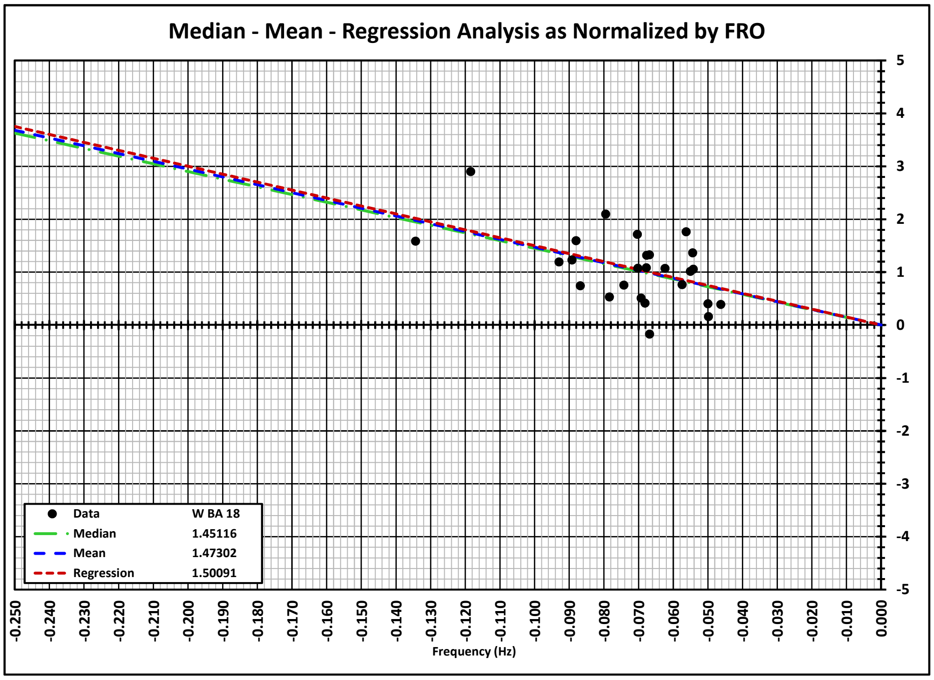
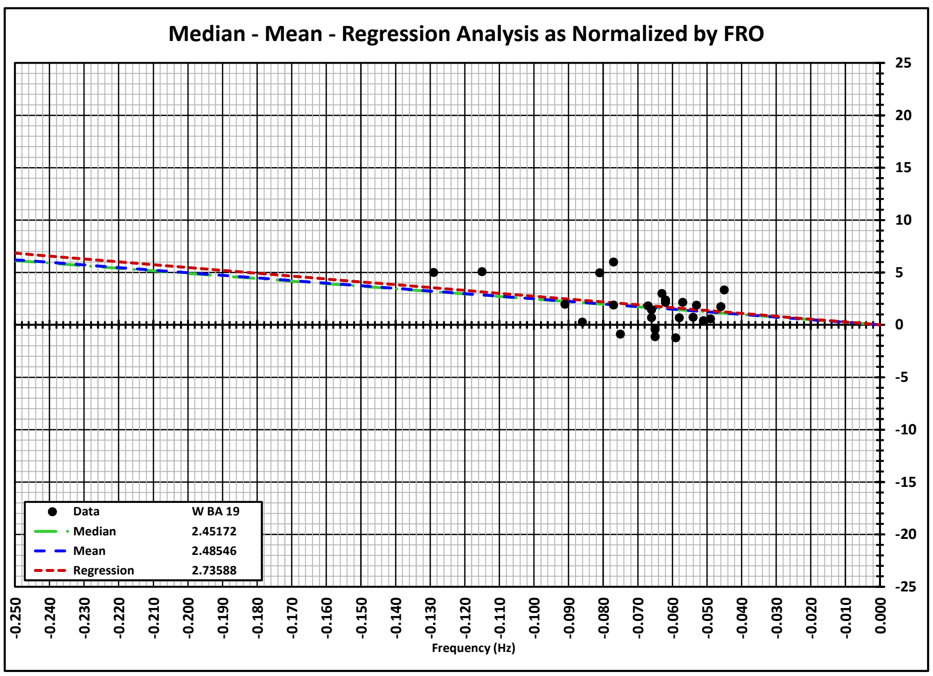
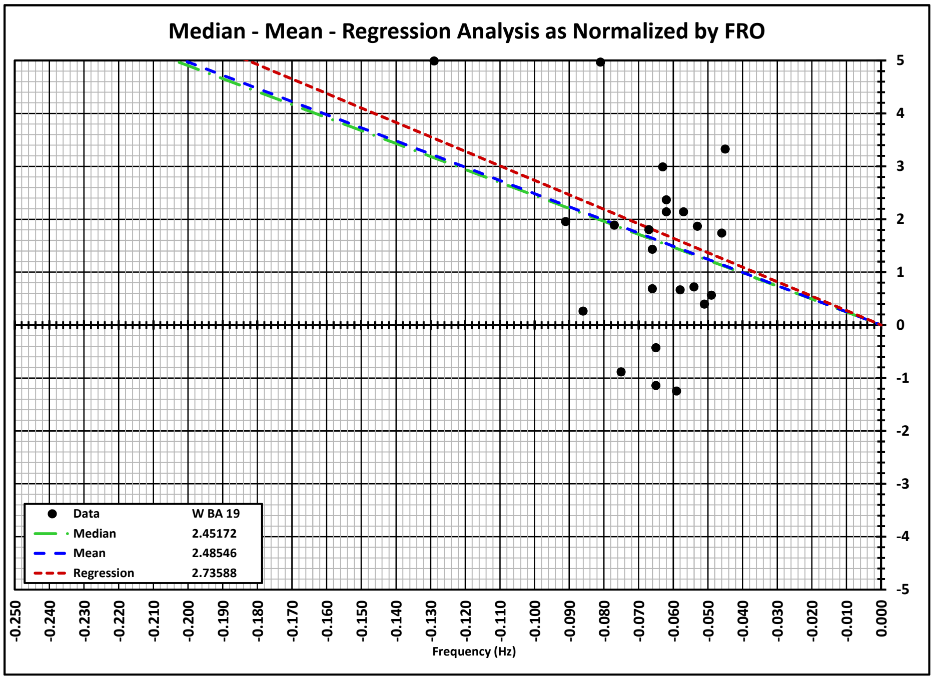
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000
5
4
3
2
1
0
-1
-2
-3
-4
-5


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 18
Median 1.45116
Mean 1.47302
Regression 1.50091
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 19
Median 2.45172
Mean 2.48546
Regression 2.73588
Frequency (Hz)


Median - Mean - Regression Analysis as Normalized by FRO
Data W BA 19
Median 2.45172
Mean 2.48546
Regression 2.73588
Frequency (Hz)
5
4
3
2
1
0
-1
-2
-3
-4
-5
-0.250
-0.240
-0.230
-0.220
-0.210
-0.200
-0.190
-0.180
-0.170
-0.160
-0.150
-0.140
-0.130
-0.120
-0.110
-0.100
-0.090
-0.080
-0.070
-0.060
-0.050
-0.040
-0.030
-0.020
-0.010
0.000

Appendix I – Derivation of the Median, Mean, and Linear Regression

Median

The median best represents a uniform one-dimensional dataset.

Uniform Distribution

In probability theory and statistics, the continuous uniform distribution or rectangular distribution is a family of probability distributions such that for each member of the family, all intervals of the same length on the distribution's support are equally probable. The support is defined by the two parameters, a and b, which are its minimum and maximum values.

Median

We have been taught in statistics that minimizing the sum of the differences error term provides the best estimate for the value for a uniform data set. Define a data set as one dimensional with values {$x_1, x_2, \ldots, x_n$}. The objective is to select a single value that best represents this data set by minimizing the sum of the residuals.

$$SDE = \sum_{i=1}^{n} \left(x_i - x_m \right)$$

Where: x_m = Best single value to represent the data set.

The result is undefined using calculus. Therefore, other logic must be used.

Organize the data from smallest to largest. Then investigate the change in total difference as the candidate median value is raised from the smallest to the largest value in the data set.

When the candidate median value is raised above the smallest data value the difference between the candidate median value and the smallest value increases, but the difference between the candidate median value and all other data values decreases by an amount equal to the increase in the difference for the smallest value times the number of data values above the candidate median value. As the candidate median value increases, the total difference from all values will decrease until exactly one half of the data values are above the candidate median value and exactly one half of the data values are below the candidate median value. If there are an even number of data values in the set, any change in the candidate median value between the data value immediately below the half and the data point immediately above the half will not change the total difference because the difference change in the increasing direction and the difference change in the decreasing direction offset each other. However, if there are an odd number of data values in the data set, the candidate median value equal to the center data value will result in a minimum of the differences.

This demonstrates that the medianis the best estimate for a set of uniform data because it minimizes the sum of the error terms for the data set.

The real question is not whether the median is an appropriate estimator, but whether the median is an appropriate estimator for the data being analyzed.

Mean

The mean best represents a normal one dimensional dataset.

Normal (Gaussian) Distribution

In probability theory, the normal (or Gaussian) distribution is a continuous probability distribution that has a bell-shaped probability density function, known as the Gaussian function or informally the bell curve, where parameter μ is the mean or expectation (location of the peak) and σ^2 is the variance, the mean of the squared deviation, (a "measure" of the width of the distribution). σ is the standard deviation. The distribution with $\mu = 0$ and $\sigma^2 = 1$ is called the standard normal. A normal distribution is often used as a first approximation to describe real-valued random variables that cluster around a single mean value.

The normal distribution is considered the most prominent probability distribution in statistics. There are several reasons for this:

- First, the normal distribution is very tractable analytically, that is, a large number of results involving this distribution can be derived in explicit form.
- Second, the normal distribution arises as the outcome of the central limit theorem, which states that under mild conditions the sum of a large number of random variables is distributed approximately normally.
- Third, the bell shape of the normal distribution makes it a convenient choice for modeling a large variety of random variables encountered in practice.

For this reason, the normal distribution is commonly encountered in practice, and is used throughout statistics, natural sciences, and social sciences as a simple model for complex phenomena. For example, the observational error in an experiment is usually assumed to follow a normal distribution, and the propagation of uncertainty is computed using this assumption. Note that a normally-distributed variable has a symmetric distribution about its mean. Quantities that grow exponentially, such as prices, incomes or populations, are often skewed to the right, and hence may be better described by other distributions, such as the log-normal distribution or Pareto distribution. In addition, the probability of seeing a normally-distributed value that is far (i.e., more than a few standard deviations) from the mean drops off extremely rapidly. As a result, statistical inference using a normal distribution is not robust to the presence of outliers (data that is unexpectedly far from the mean, due to exceptional circumstances, observational error, etc.). When outliers are expected, data may be better described using a heavy-tailed distribution such as the Student's t-distribution.

Mean

We have been taught in statistics that minimizing the sum of the squares of the error term provides the best estimate for the value for a normal data set. Let's define a data set as one dimensional with values {$x_1, x_2, \ldots, x_n$}. The objective is to select a single value that best represents this data set by minimizing the sum of the squares of the residuals.

$$SSE = \sum_{i=1}^{n} (x_i - x_m)^2$$

Where: x_m = Best single value to represent the data set.

$$SSE = \sum_{i=1}^{n} (x_i^2 - 2x_i x_m + x_m^2)$$

$$SSE = \sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + \sum_{i=1}^{n} x_m^2$$

$$SSE = \sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + nx_m^2$$

Take the derivative of ***SSE*** with respect to x_m, and set that derivative equal to zero.

$$\frac{\partial}{\partial x_m} SSE = \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} x_i^2 - \sum_{i=1}^{n} 2x_i x_m + nx_m^2 \right)$$

$$\frac{\partial}{\partial x_m} SSE = \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} x_i^2 \right) - \frac{\partial}{\partial x_m}\left(\sum_{i=1}^{n} 2x_i x_m \right) + \frac{\partial}{\partial x_m}(nx_m^2)$$

$$\frac{\partial}{\partial x_m} SSE = -2\sum_{i=1}^{n} x_i + 2nx_m = 0$$

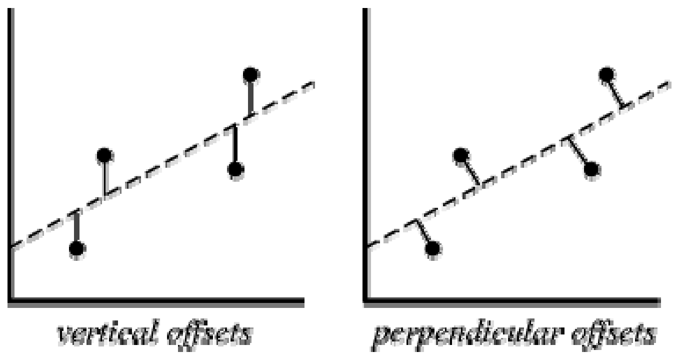
$$\frac{1}{n}\sum_{i=1}^{n} x_i = x_m = \bar{x}$$

This demonstrates that the mean is the best estimate for a set of normal data because it minimizes the sum of the squares of the error terms for the data set.

Linear Regression

A linear regression best represents a normal two dimensional dataset.

As with the one dimensional data set, the objective is to minimize the sum of the squares of the error terms. However, there may be differences that depend upon how we define the error terms.



There are three alternatives available for defining the error term. It can be defined with respect to the dependent variable alone as shown in the vertical offsets plot above. The second is to define the error in terms of the horizontal offsets (not shown). That alternative is the same as the first alternative when the independent variable is exchanged with the dependent variable. The third alternative is to define the error as the perpendicular distance from the best fit line. This is shown in the perpendicular offsets plot above. When the regression is solved using the perpendicular offsets, both variables are considered equal with respect to contribution to error, and the ranking of variables is not necessary.

Solution assuming an independent/dependent variable relationship

In the first example the error term is defined as one dimensional on the dependent variable axis. This is based on the vertical offsets shown above. The result is derived as follows:

$$SSE = \sum_{i=1}^{n}\left(y_i - \hat{y}_i\right)^2$$

Where: $\hat{y}_i$ = Best y value to represent the data set at a given x value.

Substitute a linear equation, $\hat{y}_i = ax_i + b$, for the estimated y value.

$$SSE = \sum_{i=1}^{n}\left(y_i - ax_i - b\right)^2$$

Since we now have two variables, ***a*** and ***b***, the derivative must be taken with respect to each variable. Setting each derivative equal to zero will provide two equations that can be solved for the two unknowns, ***a*** and ***b***.

$$\frac{\partial}{\partial b}SSE = \frac{\partial}{\partial b}\sum_{i=1}^{n}\left(y_i - ax_i - b\right)^2 = -2\sum_{i=1}^{n}\left(y_i - ax_i - b\right) = 0$$

$$\frac{\partial}{\partial a}SSE = \frac{\partial}{\partial a}\sum_{i=1}^{n}\left(y_i - ax_i - b\right)^2 = -2\sum_{i=1}^{n}\left(x_i y_i - ax_i^2 - bx_i\right) = 0$$

Rearrange terms and solve the two equations. Solve for b first.

$$-\sum_{i=1}^{n} y_i + a\sum_{i=1}^{n} x_i + nb = 0 \quad \Rightarrow \quad b = \tfrac{1}{n}\sum_{i=1}^{n} y_i - a\tfrac{1}{n}\sum_{i=1}^{n} x_i \quad \Rightarrow \quad b = \bar{y} - a\bar{x}$$

Substitute the result for b into the second equation and solve for a.

$$-\sum_{i=1}^{n} x_i y_i + a\sum_{i=1}^{n} x_i^2 + \left(\bar{y} - a\bar{x}\right)\sum_{i=1}^{n} x_i = 0 \quad \Rightarrow \quad a = \frac{\sum_{i=1}^{n} x_i y_i - n\overline{yx}}{\sum_{i=1}^{n} x_i^2 - n\overline{x}^2}$$

Calculate the value of a and substitute into the first equation to get the value of b. These are the most common equations used for linear regression. However, they assume that the dependent and independent variables can be identified and that the error in the dependent variable is more important than the error in the independent variable.

Solution without the independent/dependent variable relationship assumption

In this section, the problem is solved using the perpendicular offsets to determine the error terms. This provides a solution that is not dependent upon any assumption concerning the relationship between the variables.

The first step in this solution is to determine the square of the perpendicular offset from the regression line that represents the error term.

$$SSE = \sum_{i=1}^{n}\left(\frac{\left[y_i - \left(ax_i + b\right)\right]^2}{1 + a^2}\right)$$

Since we again have two variables, a and b, the derivative must be taken with respect to each variable. Setting each derivative equal to zero will provide two equations that can be solved for the two unknowns, a and b.

$$\frac{\partial}{\partial b}SSE = \frac{\partial}{\partial b}\sum_{i=1}^{n}\left(\frac{\left[y_i - \left(ax_i + b\right)\right]^2}{1 + a^2}\right) = \frac{-2}{1 + a^2}\sum_{i=1}^{n}\left(y_i - ax_i - b\right) = 0$$

$$\frac{\partial}{\partial a}SSE = \frac{\partial}{\partial a}\sum_{i=1}^{n}\left(\frac{\left[y_i - (ax_i + b)\right]^2}{1+a^2}\right)$$

$$\frac{\partial}{\partial a}SSE = \frac{-2}{1+a^2}\sum_{i=1}^{n}(y_i - ax_i - b)x_i - \sum_{i=1}^{n}\frac{(y_i - ax_i - b)^2(2a)}{(1+a^2)^2} = 0$$

Rearrange terms and solve the two equations. Solve for b first.

$$-\sum_{i=1}^{n}y_i + a\sum_{i=1}^{n}x_i + nb = 0 \quad \Rightarrow \quad b = \tfrac{1}{n}\sum_{i=1}^{n}y_i - a\tfrac{1}{n}\sum_{i=1}^{n}x_i \quad \Rightarrow \quad b = \bar{y} - a\bar{x}$$

This is the same result as before. Substitute the result for ***b*** into the second equation and solve for ***a***. The detailed intermediate equations for this solution can be found at http://mathworld.wolfram.com/LeastSquaresFittingPerpendicularOffsets.html. After much manipulation the following equations result:

$$A = \frac{1}{2}\frac{\left(\sum_{i=1}^{n}y_i^2 - n\bar{y}^2\right) - \left(\sum_{i=1}^{n}x_i^2 - n\bar{x}^2\right)}{n\bar{y}\bar{x} - \sum_{i=1}^{n}x_i y_i} \qquad \Rightarrow \qquad a = -A \pm \sqrt{A^2 + 1}$$

This solution is somewhat more complex than the vertical offset solution. That is the reason that the vertical offset solution is commonly used. In most cases, the vertical offset solution provides an adequate answer to the problem without the added complexity of the perpendicular offset solution. However, when the vertical offset solution is used, it makes a difference which variable is considered the independent variable and the dependent variable. This can significantly affect the results when the slope is large.

Additional information requires a special case linear regression

The calculation of Frequency Response requires the use of a special case linear regression. Frequency Response is defined as to be equal to zero when the frequency error is equal to zero. This information requires the modification of the linear regression used to provide the best representation of the data. The appropriate linear regression for representing Frequency Response is a regression where the regression line crosses the origin of the axis representing the two variables, frequency and Frequency Response (MW). Therefore, the previously developed general solution to the problem requires modification. This is done by setting the variable that represents the ***y-intercept*** to zero. In the above examples, the ***b*** term must be set to zero.

Special case solution assuming an independent/dependent variable relationship

In the first example the error term is defined as one dimensional on the dependent variable axis. This is based on the vertical offsets but in this case the variable representing the intercept is eliminated. The result is derived as follows:

$$SSE = \sum_{i=1}^{n}\left(y_i - \hat{y}_i\right)^2$$

Where: $\hat{y}_i$ = Best ***y*** value to represent the data set at a given ***x*** value.

Substitute a linear equation, $\hat{y}_i = ax_i$, for the estimated ***y*** value.

$$SSE = \sum_{i=1}^{n}\left(y_i - ax_i\right)^2$$

Since we now have a single variables, ***a***, the derivative must be taken with respect to that variable. Setting the derivative equal to zero will provide an equation that can be solved for the unknown, ***a***.

$$\frac{\partial}{\partial a}SSE = \frac{\partial}{\partial a}\sum_{i=1}^{n}\left(y_i - ax_i\right)^2 = -2\sum_{i=1}^{n}\left(x_i y_i - ax_i^2\right) = 0$$

Rearrange terms and solve the equation.

$$-\sum_{i=1}^{n}x_i y_i + a\sum_{i=1}^{n}x_i^2 = 0 \qquad \Rightarrow \qquad a = \frac{\sum_{i=1}^{n}x_i y_i}{\sum_{i=1}^{n}x_i^2}$$

This equation is somewhat simpler than the equation using a non-zero intercept. In the specific case that we are considering, the estimate of Frequency Response, the slope of the regression line is not expected to be large, near vertical. Therefore, the assumption of dependent and independent variables is not important to the solution. In this case, the additional complexity added by considering the horizontal offsets is not significant to the solution and has been eliminated from consideration.

Appendix J – Generator Governor Survey Instructions

NOTE: These were the instructions for the Generators Governor Survey conducted in September 2010.

Frequency Response Initiative

Generator Governor Survey

For the purposes of this survey, governors are defined as any device that implements Primary Frequency Response (speed regulation) for generators.

The survey will be sent to Generator Owners and Generator Operators.

- The survey includes all generators rated 20 MVA or higher, or plants that aggregate to a total of 75 MVA or greater net rating at the point of interconnection (i.e., wind farms, PV farms, etc.), accordance with the Statement of Compliance Registry Criteria, Rev. 5.0.
- Jointly-owned units should be reported by the operating entity.
- For combined-cycle plants, the combustion turbines and heat-recovery (steam turbine) units should be reported separately.
- Wind farms should report on a point-of-interconnection basis.
- If the unit is operable in more than one interconnection, complete the survey for operation in each of the interconnections.

NOTE: The 256-character limitation noted on the spreadsheet is a Microsoft Excel limitation on characters in a cell. If additional space is needed, please supply supplemental documentation as necessary.

When responding, please upload your response and any supporting documentation through the NERC Secure Alerts System

General Questions

1. Does your organization have a formal policy on the installation and operation of generator governors?
2. Does your organization have a testing procedure for governors? If so, how often are they tested?

Unit-Specific Questions

The following questions will all apply to each generator:

1. Unit name and number.

2. Balancing Authority (BA) in which the generator is operated (pull-down).
    a. If operable in more than one, please note all applicable BAs.
    b. If operable in more than one interconnection, complete the survey for operation in each of the interconnections.
3. Unit seasonal Net MW ratings normally reported to NERC for resource adequacy analyses:
    a. Summer Net MW rating
    b. Winter Net MW rating
4. Prime mover (steam turbine, combustion turbine, wind turbine, etc. — pull-down)
5. Fuel type (coal, oil, nuclear, etc. — pull-down)
6. Unit inertia constant (H) as modeled in dynamics analyses – the combined kinetic energy of the generator and prime-mover in watt-seconds at rated speed divided by the VA (Volt-Ampere) base.
7. What are the annual run hours for the unit (data for each of the last 3 years)?
8. What is the continuous MW rating (Pmax) of the unit?
9. What percent of time does the unit run at Pmax or valves wide-open?
    a. 0 to 30%
    b. 31% to 60%
    c. 61% to 100%
10. Equipped with a Governor? (Y/N) If not, no further answers are necessary.
11. If yes, is the governor operational? (Y/N with a comment box) If not, please explain.
    a. Is the governor normally in operation? (Y/N with a comment box) (even if not normally operated, the data on the governor is still needed)
    b. What is the normal governor mode of operation? (pull-down)
    c. Is the governor response sustainable for more than one minute if conditions remain outside of the deadband? (Y/N)
    d. Are there any regulatory restrictions regarding the operation of the governor? This should cover nuclear regulation, environmental restrictions (water temperature, emissions), water flow, etc.
    e. Does the governor respond beyond the high/low operating limit (boiler blocks)? (Y/N)
    f. Is the governor response limited by the rate of change? (Y/N)
    g. Are there any other unit-level or plant-level control schemes that would override or limit governor performance? If yes, please explain.
12. Governor Type?
    - Electronic (analog electro-hydraulic);
    - DEH (digital electro hydraulic);
    - Mechanical;
    - Other — please specify.
13. Governor manufacturer and model?
    a. If mixed vendor equipment is installed, please explain.
14. Governor Deadband setting?
    a. Deadband in(+/-) mHz

i. If in mHz is the deadband centered around a frequency reference (60 Hz or current frequency)?

b. Deadband in (+/-) RPM

i. For RPM specify number of machine poles

ii. If in RPM, is the RPM reference nominal or current RPM?

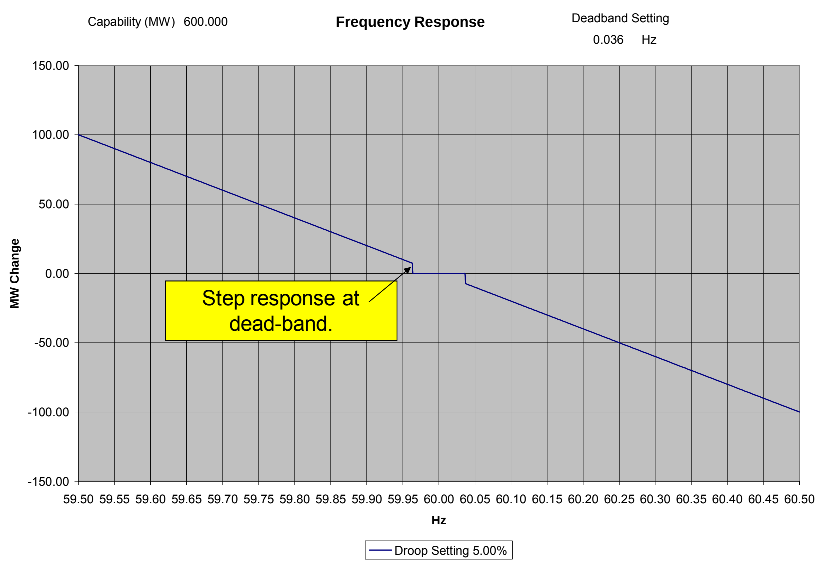
c. What is the basis for this setting?

d. Once activated, what are the conditions for which the governor action is reset?

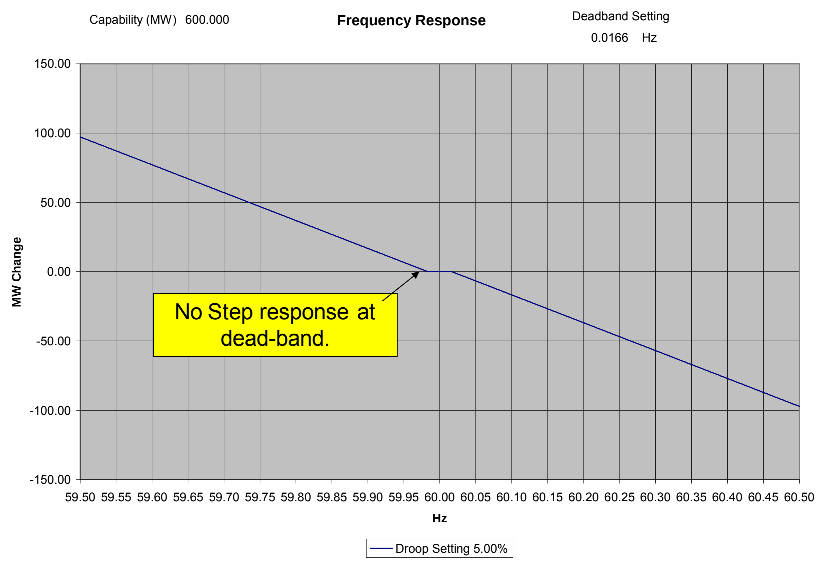
15. What is the percentage (%) droop setting on the governor?

a. What is the basis for the droop setting?

16. Does the unit Frequency Response step into the droop curve or is it linear from the deadband?



Step Implementation (step): When frequency crosses the governor dead-band setting the output of the governor “steps” into the 5% droop curve as if the dead-band did not exist.



Without Step Implementation (linear): When frequency crosses the governor dead-band setting the output of the governor adds proportional output toward the droop curve end point.

17. Prime mover control mode – What is the normally used Turbine Control mode(s)? If more than one is prevalently used, select a primary and explain.
    - Turbine manual
    - Thermally-limited
    - Turbine following
    - Boiler following
    - Part-load
    - Pre-select
    - MW set point
    - Coordinated control
    - Other (please explain) If more than one is prevalently used, select a primary and explain.

18. Do market rules restrict or override governor speed controls? (Y/N) If yes, please explain.

For steam generator controls (boiler controls) or combined cycle central station controls:

19. Does the boiler control or combined cycle central station control have a frequency input? (Y/N) If yes, answer the following questions:
    a. Deadband in(+/-) mHz
        i. If in mHz is the deadband centered around a frequency reference (60 Hz or current frequency)?

b. Deadband in (+/-) RPM
   i. For RPM specify number of machine Poles
   ii. If in RPM, is the RPM reference nominal or current RPM?
c. What is the basis for this setting?

20. Does the control's Frequency Response step into the droop curve or is it linear from the deadband?
21. What is the steam turbine control mode? (boiler following, turbine following, coordinated control)
22. Do the unit or plant controls over-ride governor speed control or are the control parameters supportive? (Y/N)
23. Does the boiler operate under variable/sliding pressure? (Y/N)
    a. What is the control/governor valve position percentage (%) during variable pressure operation?
24. Do unit or plant economic controls over-ride governor speed control? (Y/N)

Event Performance Data

The following five questions are to be answered for each generator to ascertain its performance during the specified frequency events (one per interconnection). The frequency events data to be reported are:

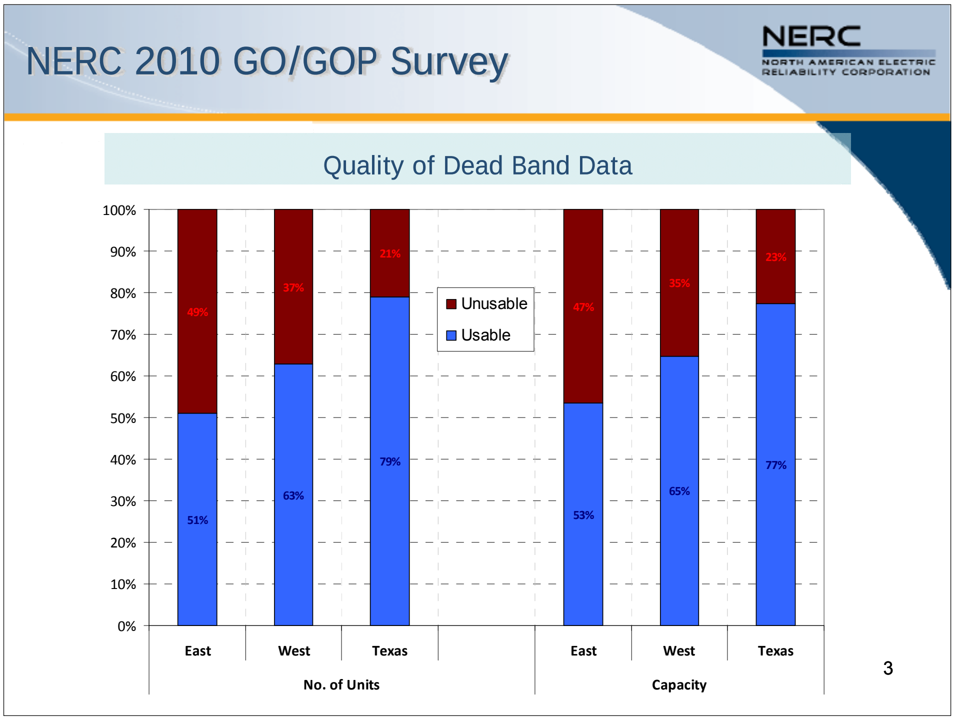
Interconnection	Date	Time	Time Zone
Eastern	8/16/2010	14:25:29	CST
Western	8/12/2010	1:06:15	CST
Texas	8/20/2010	14:44:03	CST
Québec	12/10/2009	15:09:31	EST

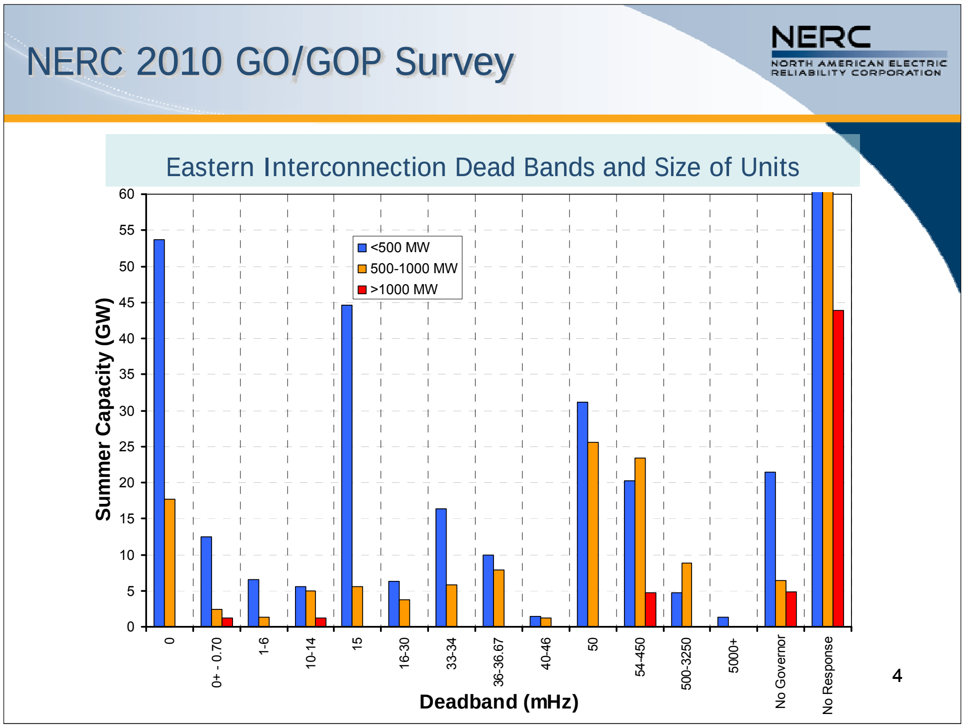
25. Was the unit on-line during the event? (Y/N)
26. Pre-event generation (MW) – Enter the MW output of the generator at the time just before the event began.
27. Post-event generation (MW) – Enter the MW output of the generator after the event that was reflects the response by the governor to the frequency deviation.
28. Time to achieve post-event response (seconds) – Enter the time (in seconds) it took to achieve the MW response noted in question 27.
29. Comments (256 characters) – Enter any comments necessary. If no data is available for the event, note that here.

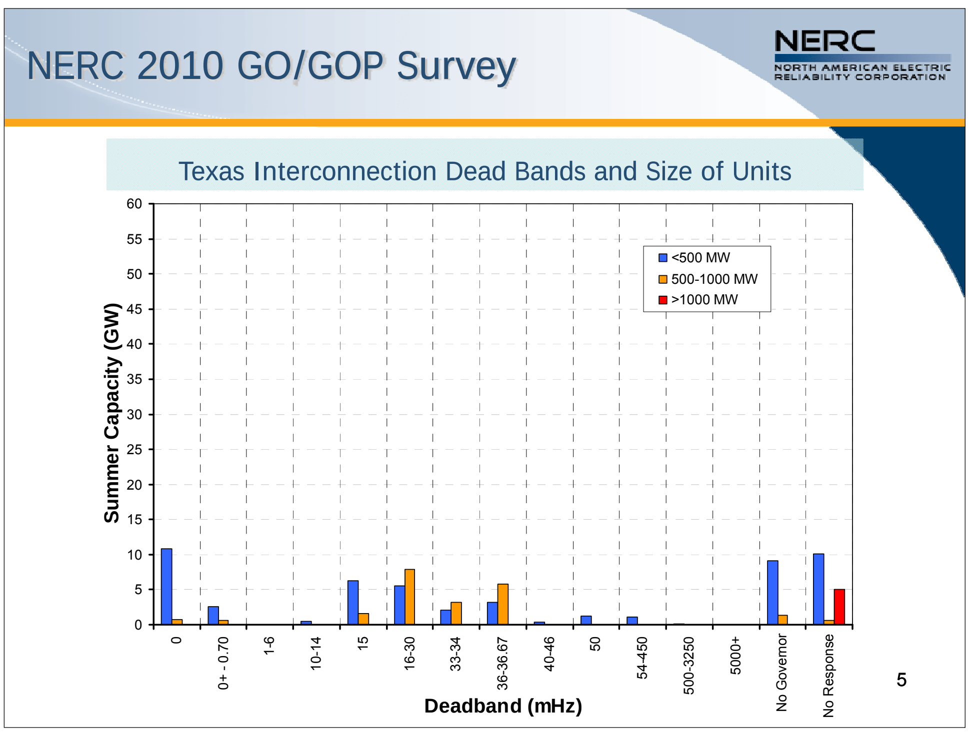
Appendix K – Generator Governor Survey Summary

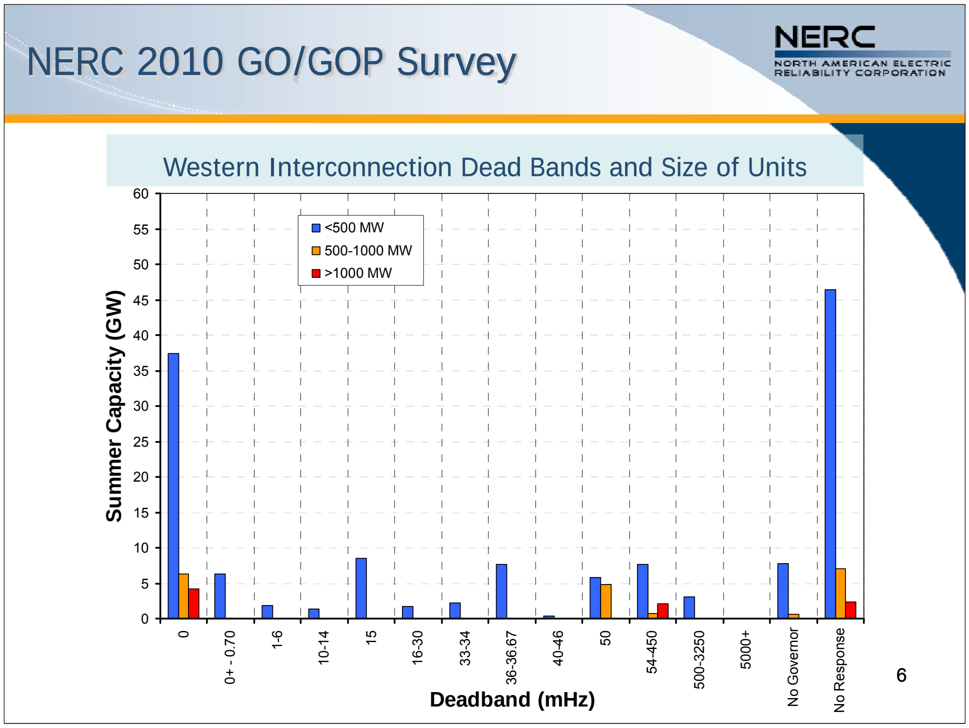
The following are slides that summarize the responses of the 2010 Generator Governor Survey.

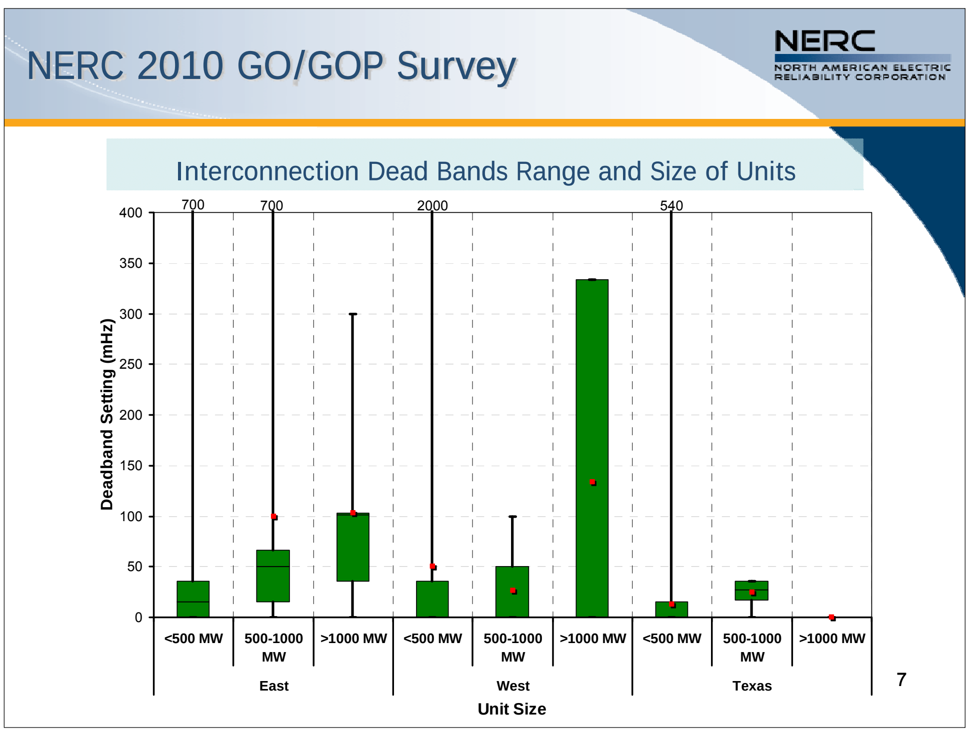
Deadband Settings

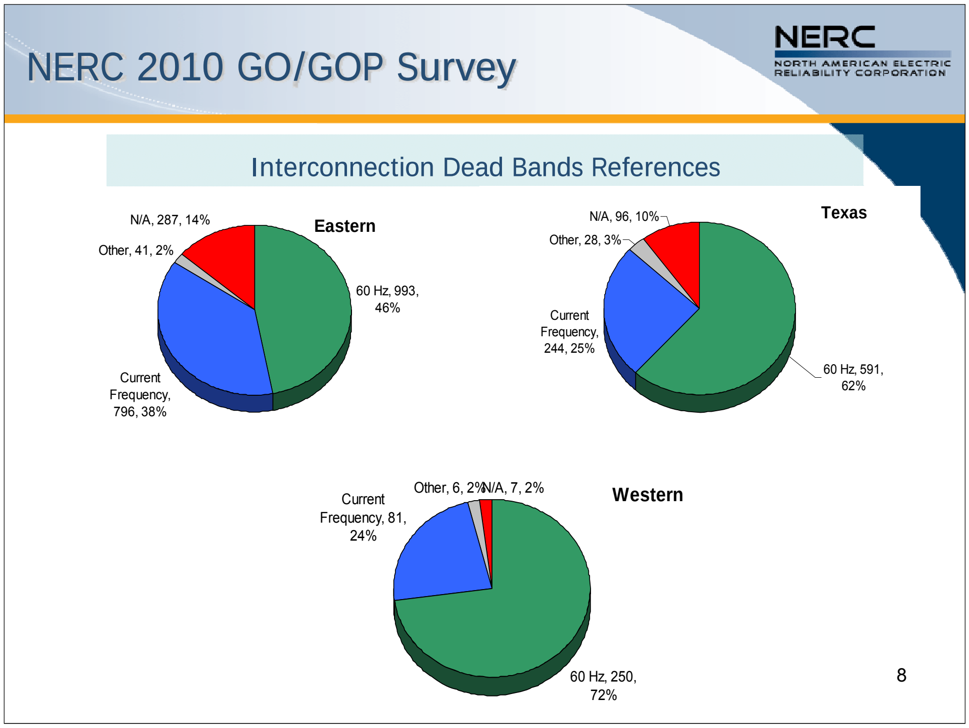



NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Eastern Interconnection Dead Bands and Size of Units
Summer Capacity (GW)
Deadband (mHz)
<500 MW
500-1000 MW
>1000 MW
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
4

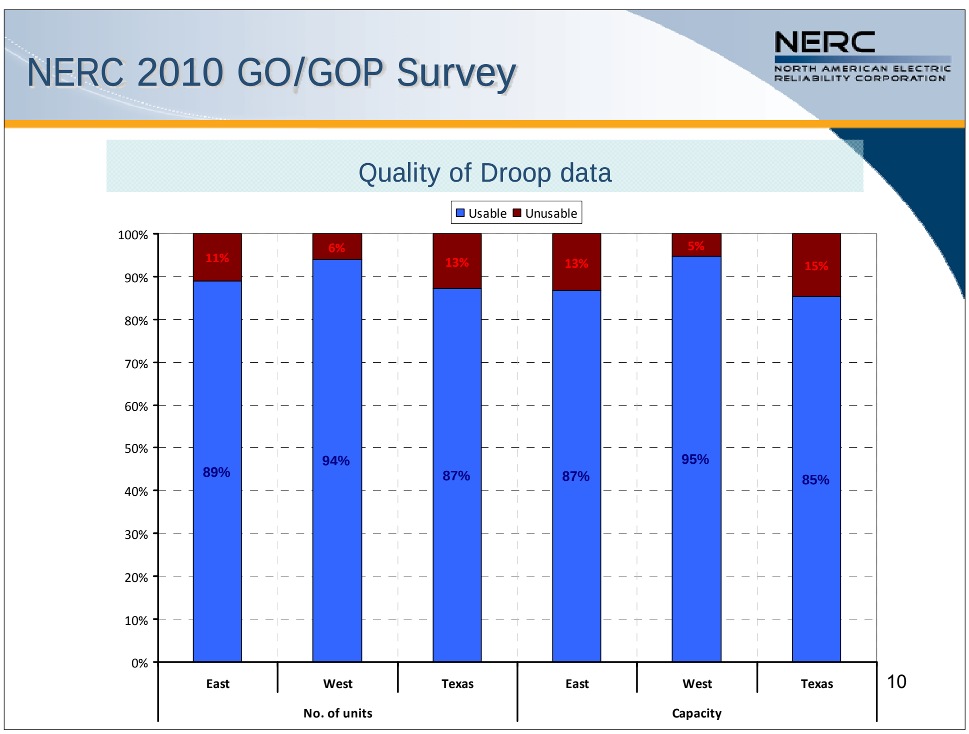

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Texas Interconnection Dead Bands and Size of Units
Summer Capacity (GW)
Deadband (mHz)
<500 MW
500-1000 MW
>1000 MW
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
5

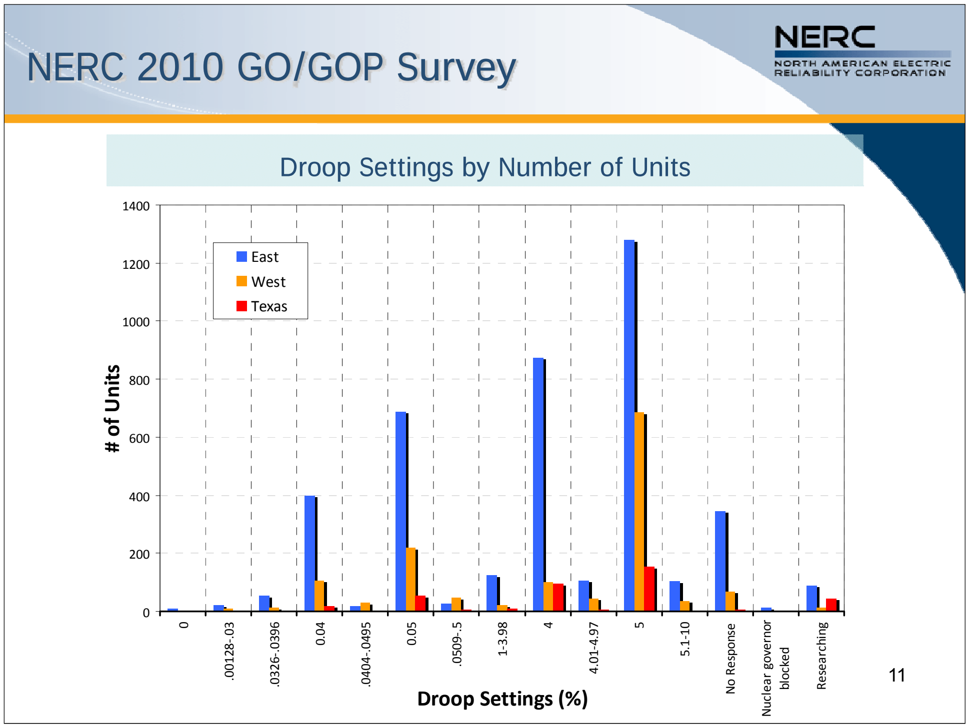

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Western Interconnection Dead Bands and Size of Units
<500 MW
500-1000 MW
>1000 MW
Summer Capacity (GW)
60
55
50
45
40
35
30
25
20
15
10
5
0
0
0+ - 0.70
1-6
10-14
15
16-30
33-34
36-36.67
40-46
50
54-450
500-3250
5000+
No Governor
No Response
Deadband (mHz)
6

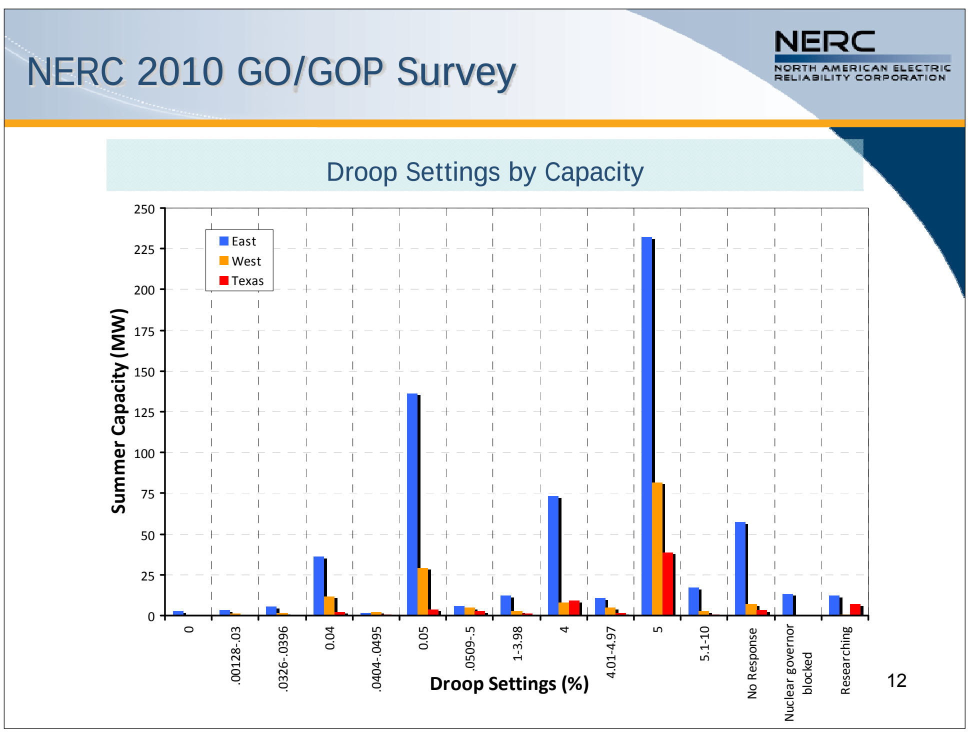

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Interconnection Dead Bands Range and Size of Units
700
700
2000
540
Deadband Setting (mHz)
400
350
300
250
200
150
100
50
0
<500 MW
500-1000 MW
>1000 MW
<500 MW
500-1000 MW
>1000 MW
<500 MW
500-1000 MW
>1000 MW
East
West
Texas
Unit Size
7

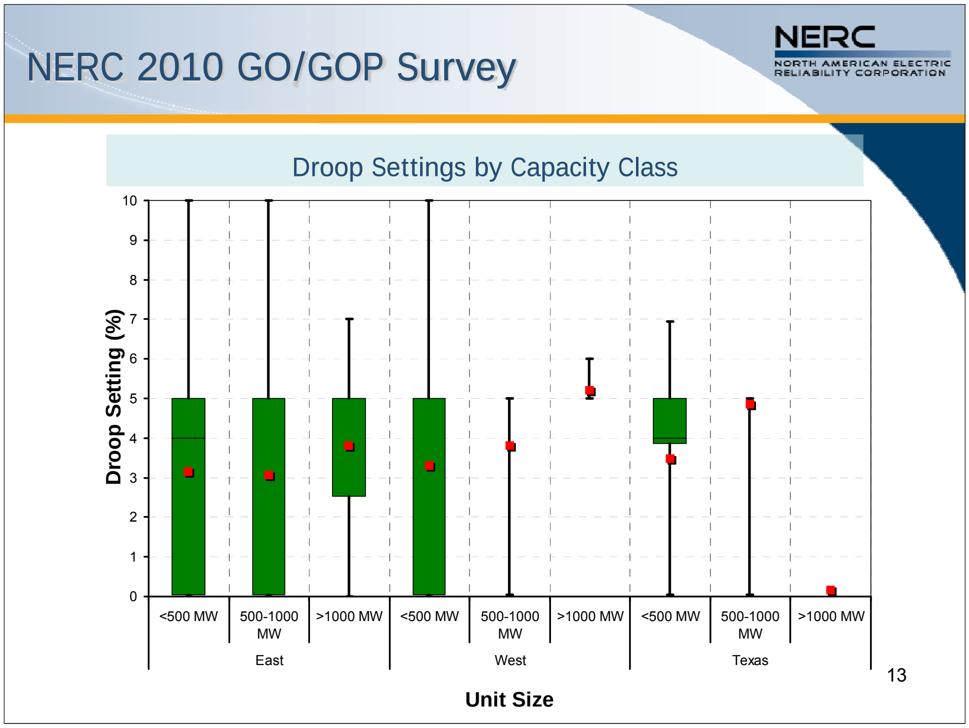


Droop Settings

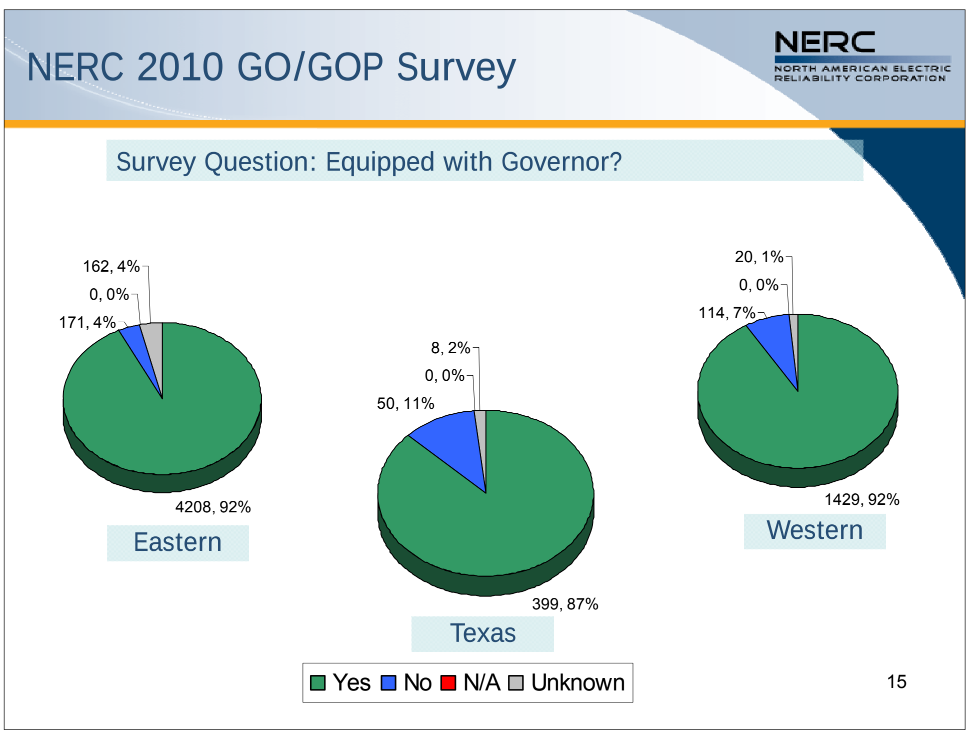


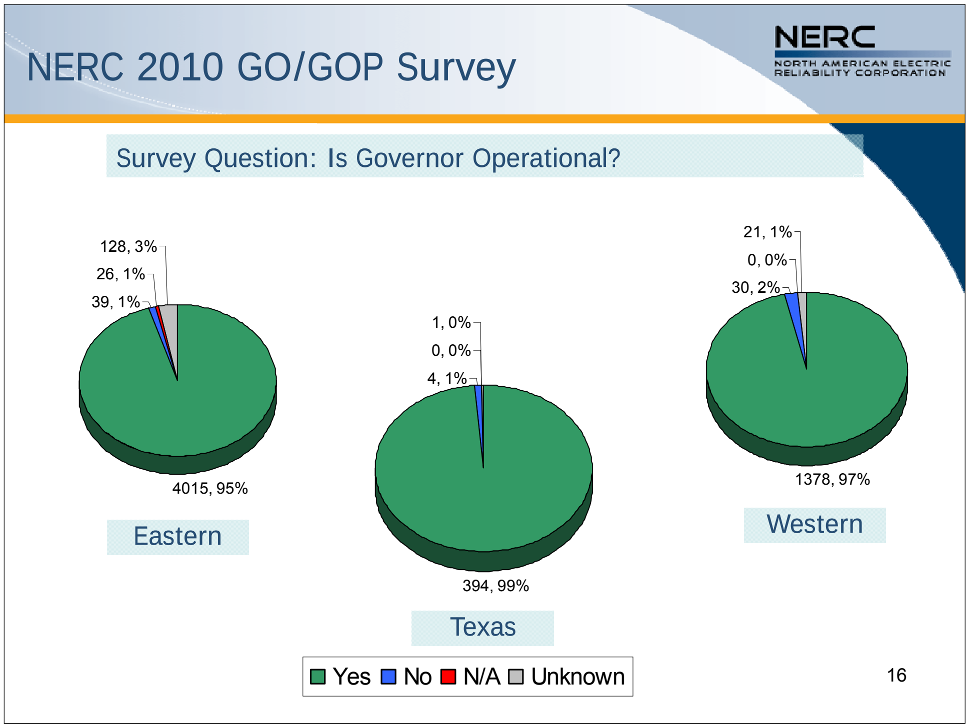

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Droop Settings by Number of Units
East
West
Texas
# of Units
1400
1200
1000
800
600
400
200
0
0
.00128-.03
.0326-.0396
0.04
.0404-.0495
0.05
.0509-.5
1-3.98
4
4.01-4.97
5
5.1-10
No Response
Nuclear governor blocked
Researching
Droop Settings (%)
11

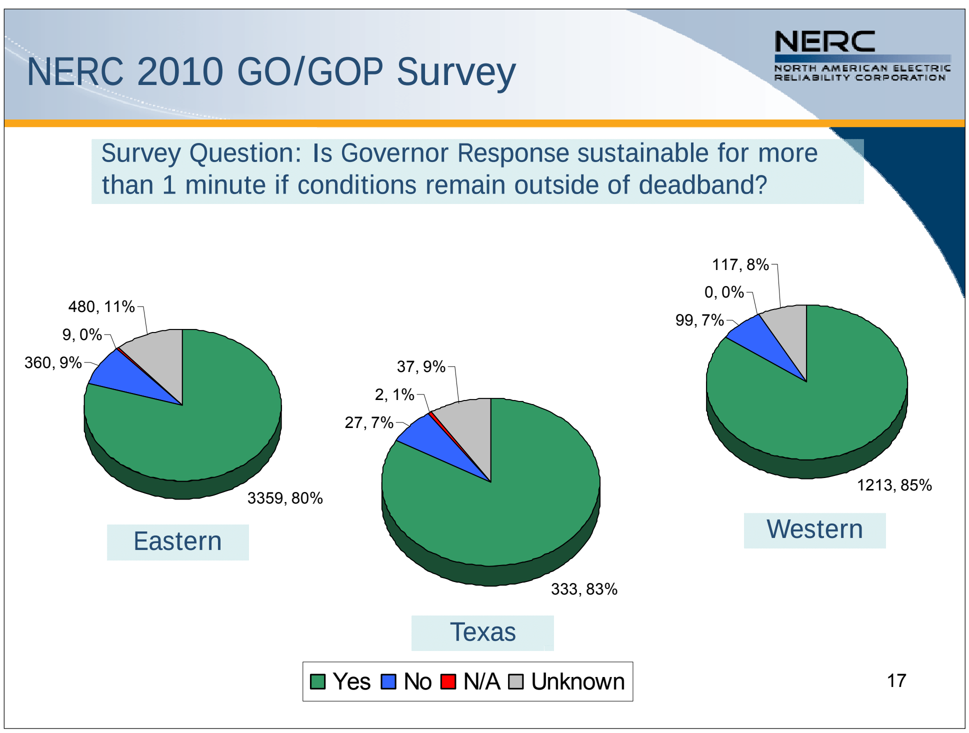

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Droop Settings by Capacity
East
West
Texas
Summer Capacity (MW)
250
225
200
175
150
125
100
75
50
25
0
0
.00128-.03
.0326-.0396
0.04
.0404-.0495
0.05
.0509-.5
1-3.98
4
4.01-4.97
5
5.1-10
No Response
Nuclear governor blocked
Researching
Droop Settings (%)
12

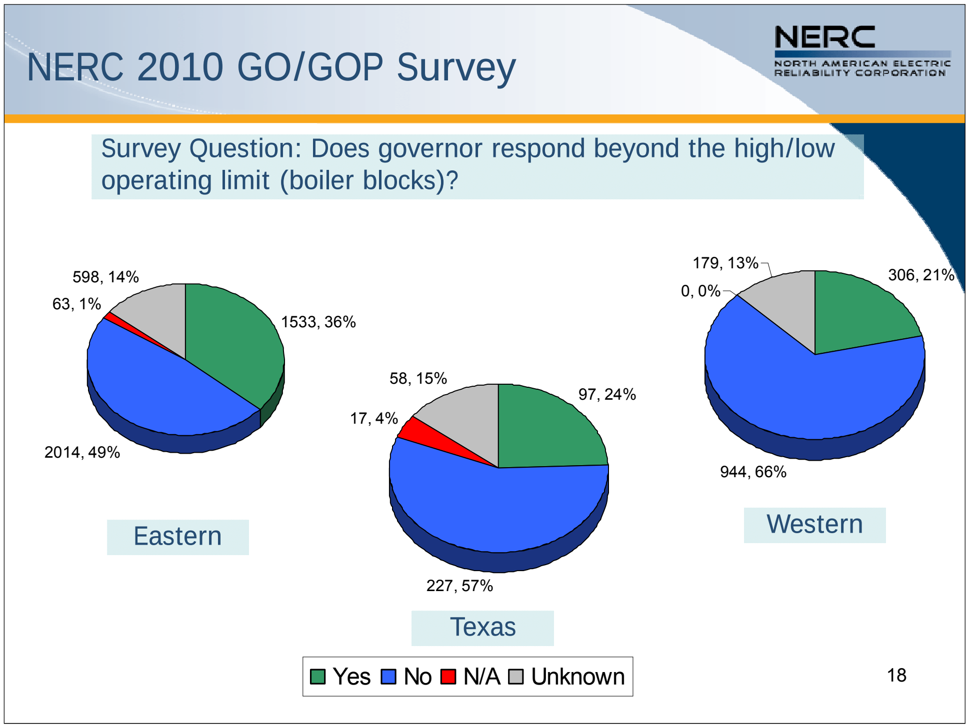


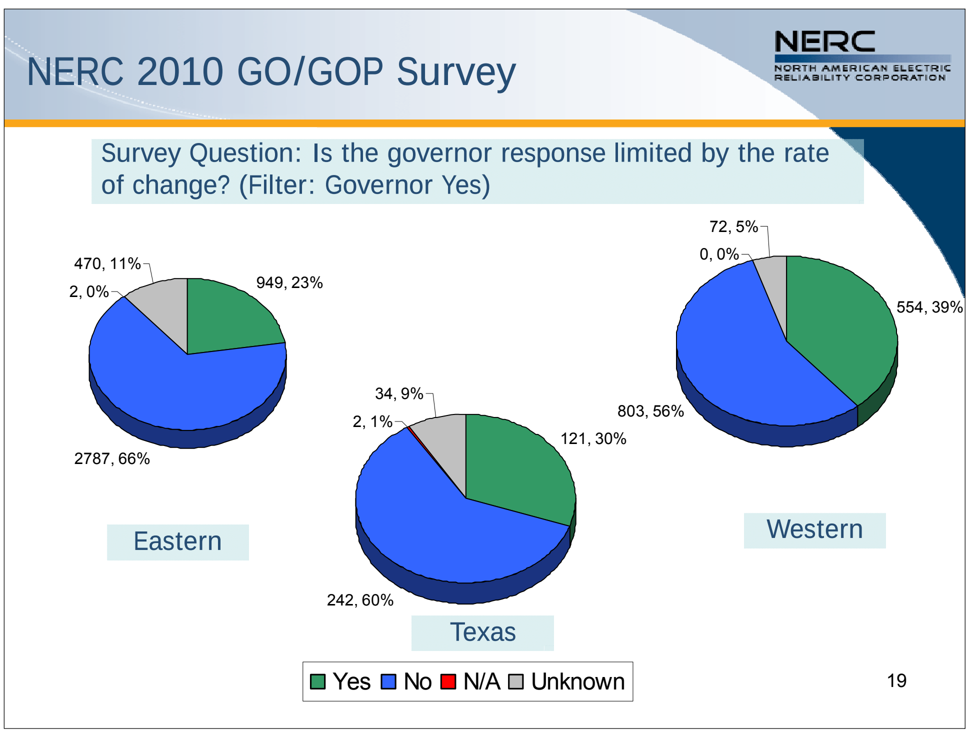
Results of Other Survey Questions

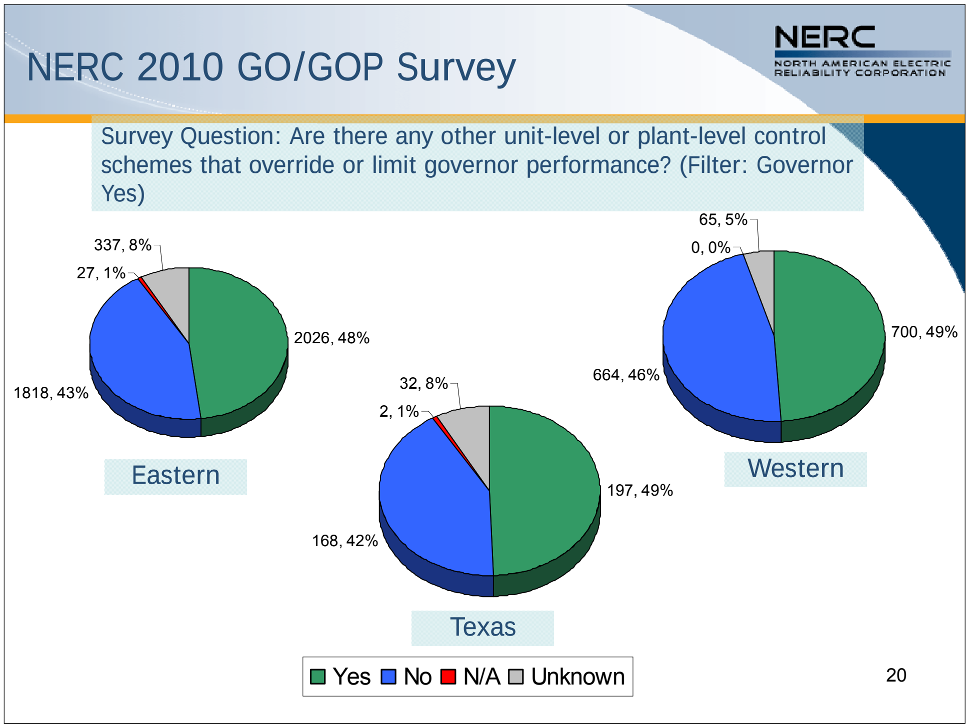


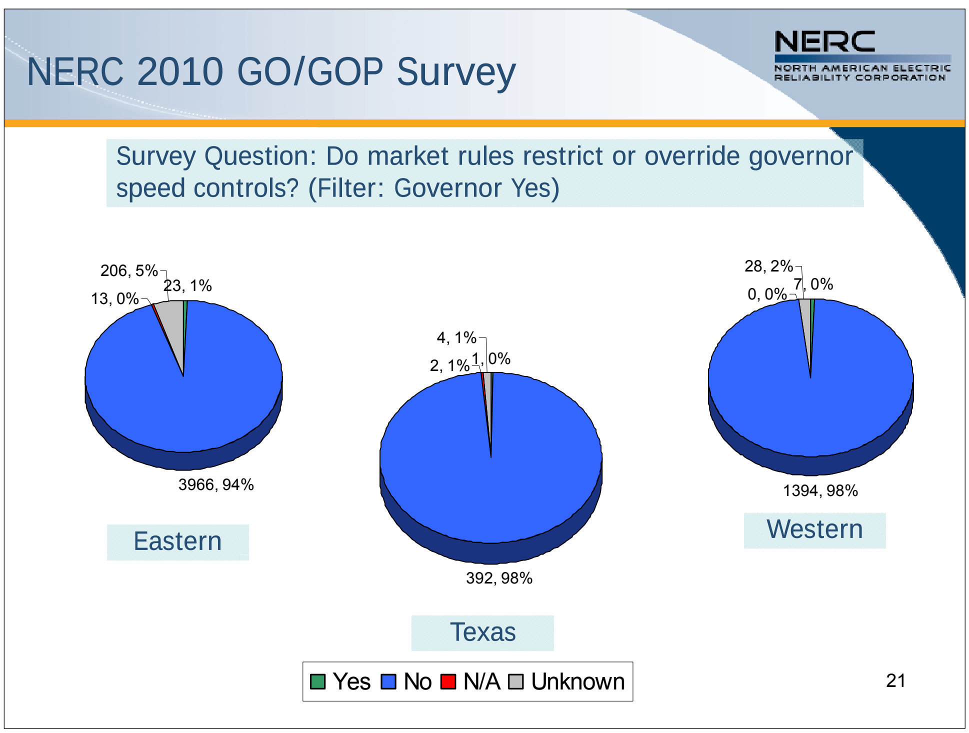

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is Governor Operational?
128, 3%
26, 1%
39, 1%
4015, 95%
Eastern
1, 0%
0, 0%
4, 1%
394, 99%
Texas
21, 1%
0, 0%
30, 2%
1378, 97%
Western
Yes No N/A Unknown
16

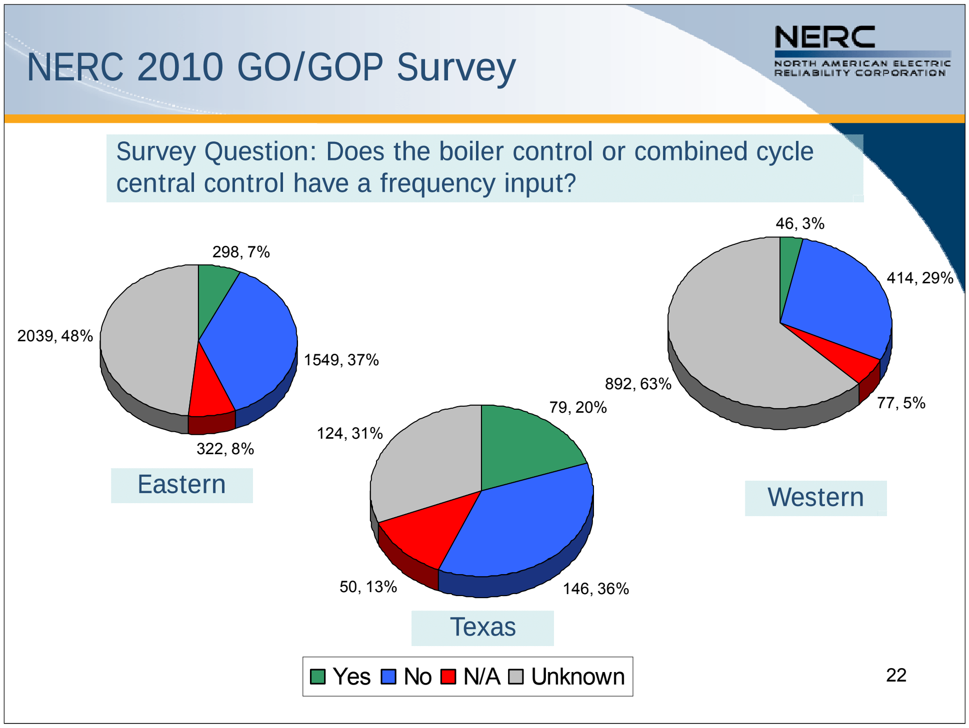

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is Governor Response sustainable for more than 1 minute if conditions remain outside of deadband?
480, 11%
9, 0%
360, 9%
3359, 80%
Eastern
37, 9%
2, 1%
27, 7%
333, 83%
Texas
117, 8%
0, 0%
99, 7%
1213, 85%
Western
Yes No N/A Unknown
17

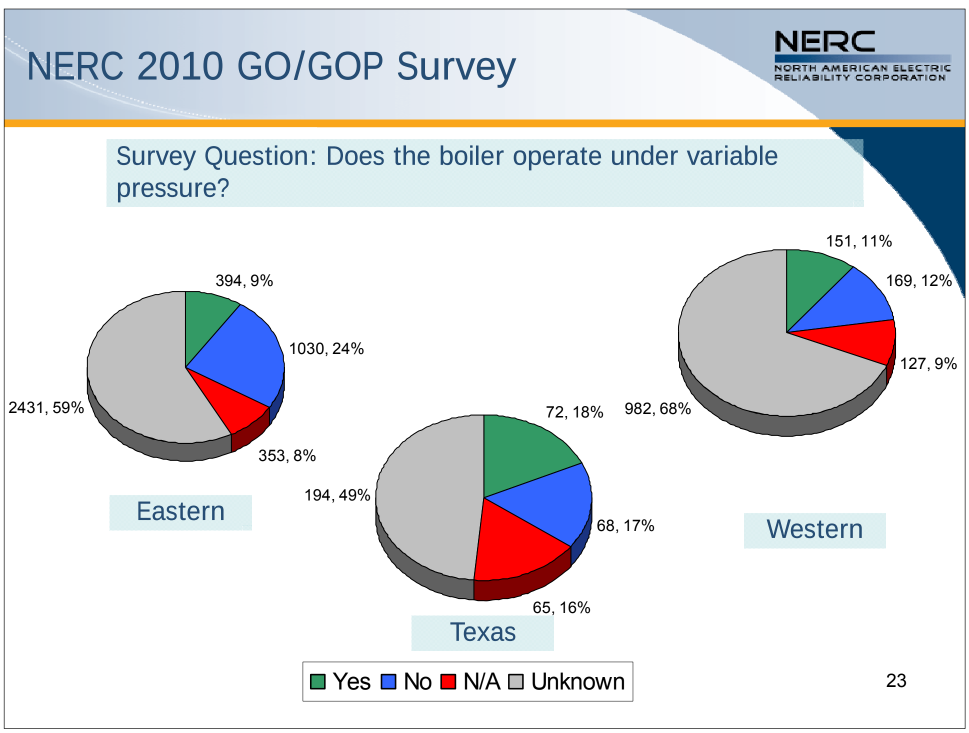

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does governor respond beyond the high/low operating limit (boiler blocks)?
598, 14%
63, 1%
1533, 36%
2014, 49%
Eastern
58, 15%
97, 24%
17, 4%
227, 57%
Texas
179, 13%
0, 0%
306, 21%
944, 66%
Western
Yes No N/A Unknown
18

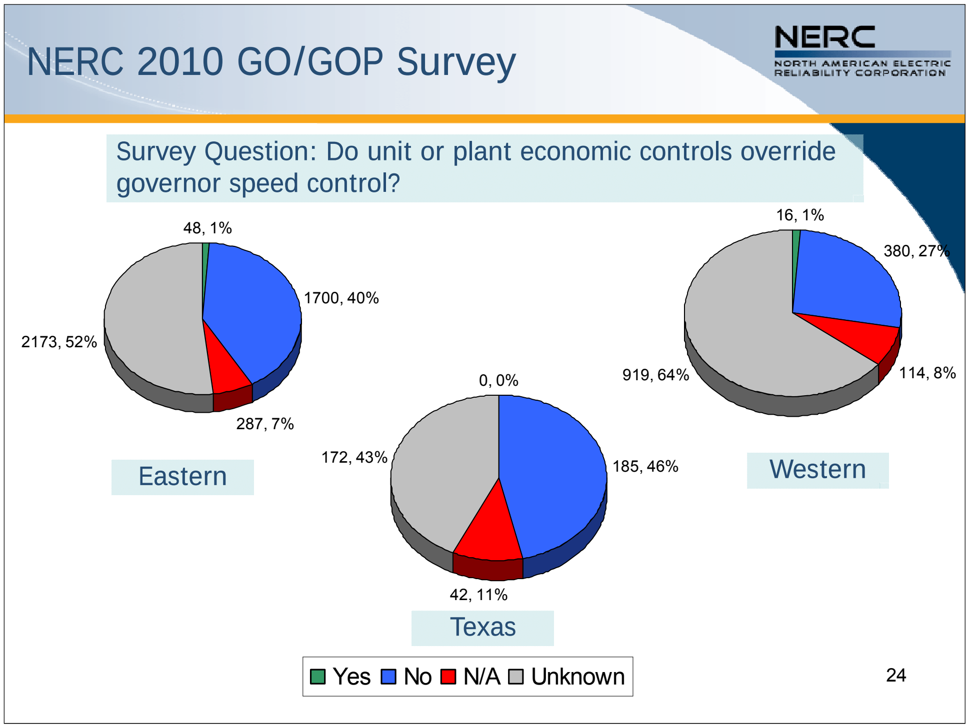

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Is the governor response limited by the rate of change? (Filter: Governor Yes)
470, 11%
2, 0%
949, 23%
2787, 66%
Eastern
34, 9%
2, 1%
121, 30%
242, 60%
Texas
72, 5%
0, 0%
554, 39%
803, 56%
Western
Yes No N/A Unknown
19


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Are there any other unit-level or plant-level control schemes that override or limit governor performance? (Filter: Governor Yes)
337, 8%
27, 1%
2026, 48%
1818, 43%
Eastern
32, 8%
2, 1%
197, 49%
168, 42%
Texas
65, 5%
0, 0%
700, 49%
664, 46%
Western
Yes No N/A Unknown
20

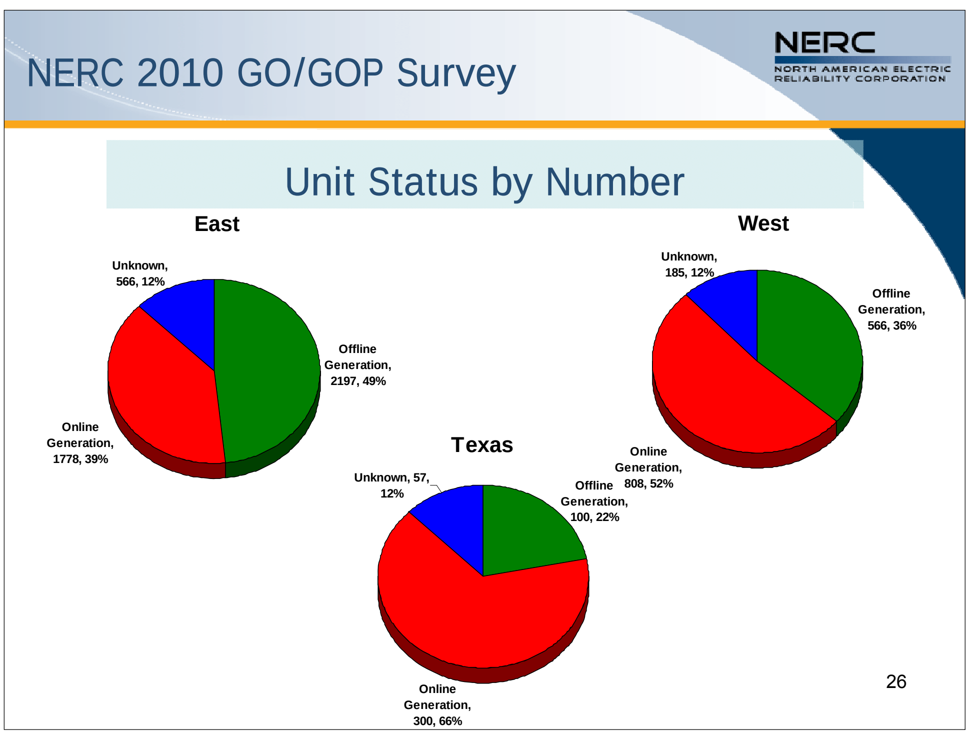

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Do market rules restrict or override governor speed controls? (Filter: Governor Yes)
206, 5%
23, 1%
13, 0%
3966, 94%
Eastern
4, 1%
2, 1%
1, 0%
392, 98%
Texas
28, 2%
7, 0%
0, 0%
1394, 98%
Western
Yes No N/A Unknown
21

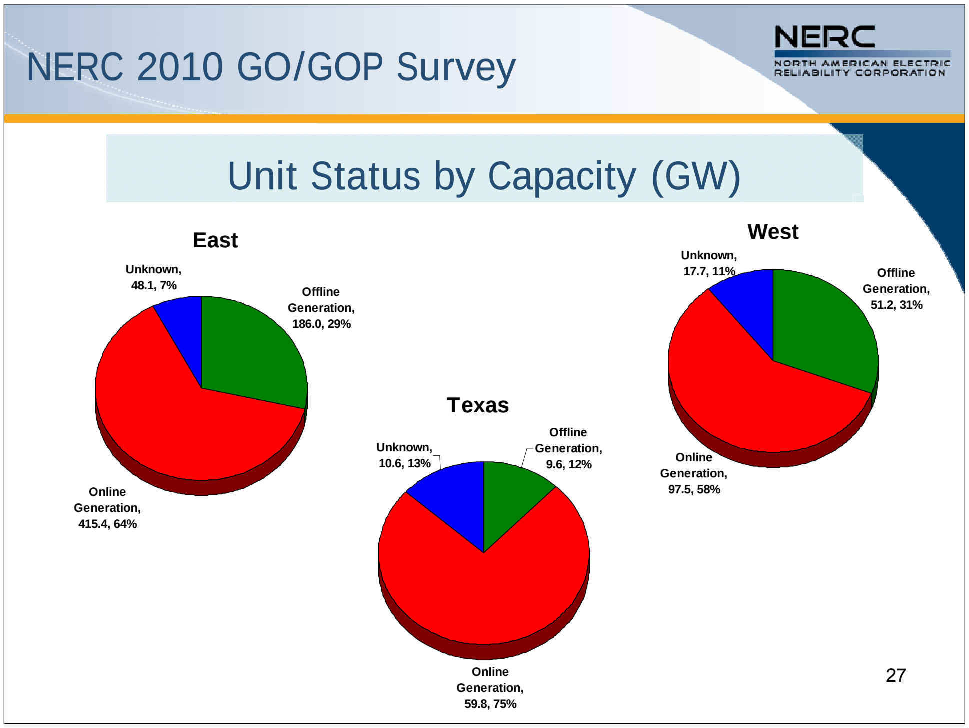

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does the boiler control or combined cycle central control have a frequency input?
298, 7%
1549, 37%
322, 8%
2039, 48%
Eastern
79, 20%
146, 36%
50, 13%
124, 31%
Texas
46, 3%
414, 29%
77, 5%
892, 63%
Western
Yes No N/A Unknown
22

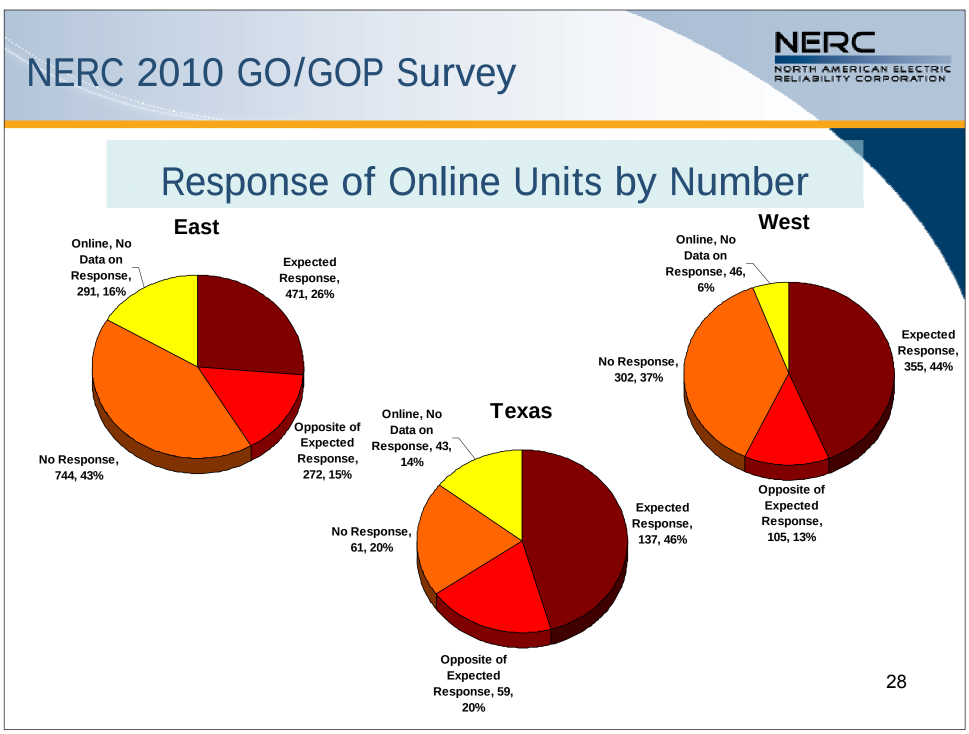

NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Survey Question: Does the boiler operate under variable pressure?
394, 9%
1030, 24%
353, 8%
2431, 59%
Eastern
72, 18%
68, 17%
65, 16%
194, 49%
Texas
151, 11%
169, 12%
127, 9%
982, 68%
Western
Yes No N/A Unknown
23

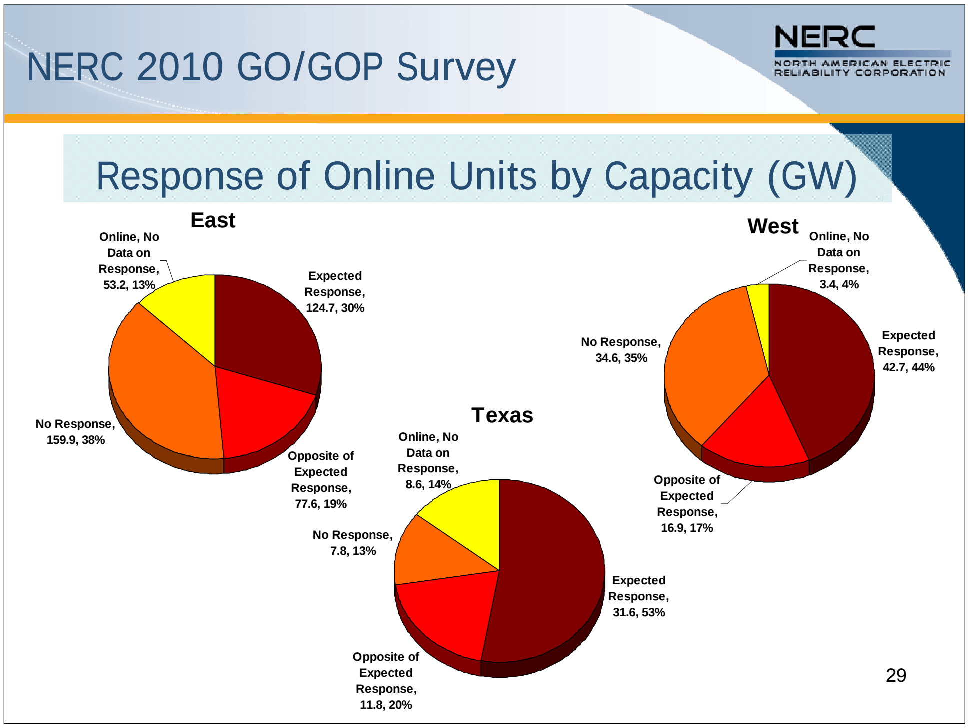


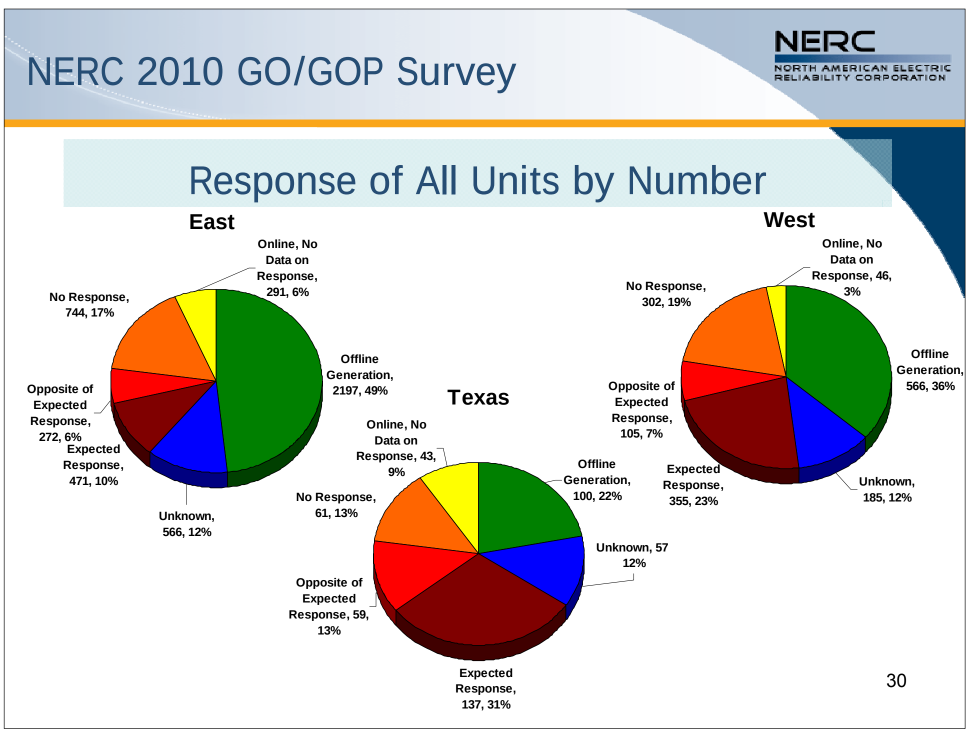
Survey Event Data

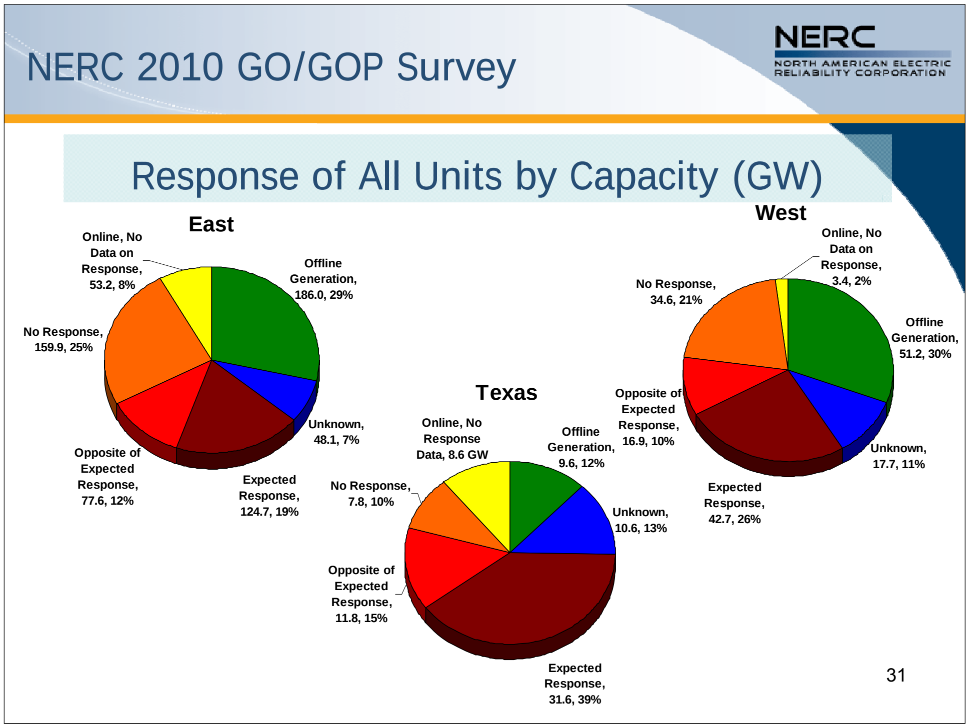



NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Unit Status by Capacity (GW)
East
Unknown, 48.1, 7%
Offline Generation, 186.0, 29%
Online Generation, 415.4, 64%
Texas
Unknown, 10.6, 13%
Offline Generation, 9.6, 12%
Online Generation, 59.8, 75%
West
Unknown, 17.7, 11%
Offline Generation, 51.2, 31%
Online Generation, 97.5, 58%
27


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of Online Units by Number
East
Online, No Data on Response, 291, 16%
Expected Response, 471, 26%
Opposite of Expected Response, 272, 15%
No Response, 744, 43%
Texas
Online, No Data on Response, 43, 14%
Expected Response, 137, 46%
No Response, 61, 20%
Opposite of Expected Response, 59, 20%
West
Online, No Data on Response, 46, 6%
Expected Response, 355, 44%
No Response, 302, 37%
Opposite of Expected Response, 105, 13%
28


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of Online Units by Capacity (GW)
East
Online, No Data on Response, 53.2, 13%
Expected Response, 124.7, 30%
No Response, 159.9, 38%
Opposite of Expected Response, 77.6, 19%
West
Online, No Data on Response, 3.4, 4%
No Response, 34.6, 35%
Expected Response, 42.7, 44%
Opposite of Expected Response, 16.9, 17%
Texas
Online, No Data on Response, 8.6, 14%
No Response, 7.8, 13%
Expected Response, 31.6, 53%
Opposite of Expected Response, 11.8, 20%
29


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of All Units by Number
East
Online, No Data on Response, 291, 6%
No Response, 744, 17%
Offline Generation, 2197, 49%
Opposite of Expected Response, 272, 6%
Expected Response, 471, 10%
Unknown, 566, 12%
West
Online, No Data on Response, 46, 3%
No Response, 302, 19%
Offline Generation, 566, 36%
Opposite of Expected Response, 105, 7%
Expected Response, 355, 23%
Unknown, 185, 12%
Texas
Online, No Data on Response, 43, 9%
Offline Generation, 100, 22%
No Response, 61, 13%
Unknown, 57 12%
Opposite of Expected Response, 59, 13%
Expected Response, 137, 31%
30


NERC 2010 GO/GOP Survey
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Response of All Units by Capacity (GW)
East
Online, No Data on Response, 53.2, 8%
Offline Generation, 186.0, 29%
No Response, 159.9, 25%
Unknown, 48.1, 7%
Opposite of Expected Response, 77.6, 12%
Expected Response, 124.7, 19%
Texas
Online, No Response Data, 8.6 GW
Offline Generation, 9.6, 12%
No Response, 7.8, 10%
Unknown, 10.6, 13%
Opposite of Expected Response, 11.8, 15%
Expected Response, 31.6, 39%
West
Online, No Data on Response, 3.4, 2%
No Response, 34.6, 21%
Offline Generation, 51.2, 30%
Opposite of Expected Response, 16.9, 10%
Unknown, 17.7, 11%
Expected Response, 42.7, 26%
31

Appendix L – References

Training Document - Policy 1 Generation Control and Performance, February 24, 2003. NERC

Niemeyer, S. *Frequency Regulation—Is Your Plant Compliant?*
Ibrahim Abdur-Rahman, Sydney & Ricardo Vera, PE

Eto, J.H. et al. 2010. *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*. LBNL-4143E. Berkeley: Lawrence Berkeley National Laboratory

Analysis of Eastern Interconnection Frequency Response, February 2011. NERC

Exhibit H

Frequency Response Initiative Supplemental Report – IFRO Simulations (DRAFT)

000297

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT

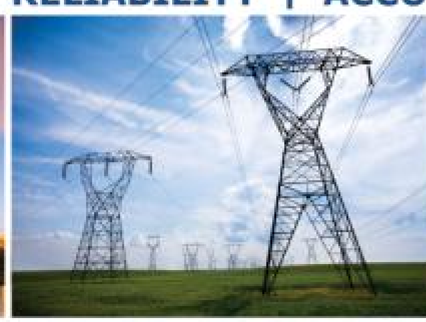
Frequency Response Initiative

Supplemental Report – IFRO Simulations

March 2013

RELIABILITY | ACCOUNTABILITY



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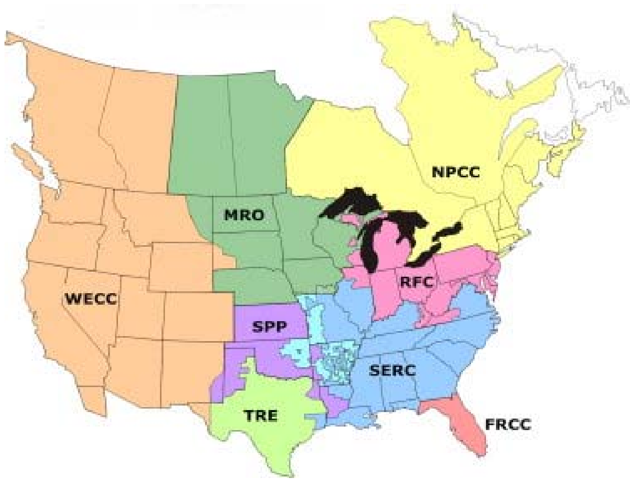
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation's (NERC) mission is to ensure the reliability of the North American bulk power system. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and summer and winter forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. ERO activities in Canada related to the reliability of the bulk power system are recognized and overseen by the appropriate governmental authorities in that country.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map and table below. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.



Note: The highlighted area between SPP RE and SERC denotes overlapping Regional area boundaries. For example, some load-serving entities participate in one Region and their associated transmission owner/operators in another.

NERC Regional Entities	
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP RE** Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	**TRE** Texas Reliability Entity
RFC ReliabilityFirst Corporation	**WECC** Western Electricity Coordinating Council

[1] As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro that makes reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

Introduction

This report is a supplement to the Frequency Response Initiative report of October 2012 for the purpose of supporting the filing of Standard BAL-003-1 – Frequency Response with the Federal Energy Regulatory Commission. This analysis was requested by the NERC Board of Trustees (Board) when the Board accepted the initiative report. This report contains the results of stability simulation testing of the Interconnection Frequency Response Obligations (IFROs) prescribed for the Eastern, ERCOT, and Western Interconnections. Stability testing was not performed for the Québec Interconnection.

The following IFROs were tested:

Table A: Recommended IFROs				
	Eastern	Western	ERCOT	Units
Starting Frequency	59.974	59.976	59.963	Hz
Max. Delta Frequency	0.449	0.291	0.473	Hz
Resource Contingency Protection Criteria	4,500	2,740	2,750	MW
Credit for LR	–	300	1,400	MW
IFRO[2]	-1,002	-840	-286	MW/0.1Hz
Absolute Value of IFRO	1,002	840	286	MW/0.1Hz

The cases for the interconnections were tested against the following recommended Resource Contingencies:

Table B: Recommended Resource Contingency Protection Criteria			
Interconnection	Resource Contingency	Basis	MW
Eastern	Largest Resource Event in Last 10 Years	August 4, 2007 Disturbance	4,500
Western	Largest N-2 Event	2 Palo Verde Units	2,740[3]
ERCOT	Largest N-2 Event	2 South Texas Project Units	2,750[4]

[2] IFRO = $CB_R \times \frac{\text{Resource Contingency Protection Criteria}}{10 \times (Starting\ Frequency - Minimum\ Frequency\ Limit - CC_{ADJ})}$

[3] Net winter ratings per Form EIA-860 reporting

[4] Net rating from ERCOT Resource Asset Registration Form (RARF)

The contingencies were simulated with associated load reduction actions including 300 MW tripped by a remedial action scheme (RAS) for the Western Interconnection and dropping of 1,300 MW[5] of Load Resources in ERCOT.

All simulations, due to limitations of the programs, assumed an initial frequency (Value A) of 60.0 Hz. Simulations for the Western Interconnection were conducted using the General Electric PSLF program, while simulations for the Eastern and ERCOT Interconnections were performed with the Siemens PSS®E program.

These IFRO tests were conducted to be informative for the filing of NERC Reliability Standard BAL-003-1 — Frequency Response and Frequency Bias Setting Frequency Response. These tests will be re-run during the annual review prescribed in the standard in the fall of 2013 to determine if adjustments need to be made to the IFROs for 2014.

This analysis was performed by the NERC Reliability Initiatives and System Analysis staff.

[5] The on-peak Load Resource evaluated in the FRI report was 1,400 MW, but the light-load case only included 1,300 MW of Load Resources armed to trip.

Findings

Western Interconnection

The dynamic simulation testing of the Western Interconnection IFRO indicated that the frequency nadir remains sufficiently above the UFLS threshold of 59.5 Hz with the prescribed 840 MW/0.1 Hz IFRO.

ERCOT Interconnection

The dynamic simulation testing of the ERCOT Interconnection IFRO revealed that a slightly higher (about 350 MW/0.1 Hz) frequency response than the prescribed 286 MW/0.1 Hz IFRO was necessary to keep the frequency nadir sufficiently above the UFLS threshold of 59.3 Hz. Consequently, the IFRO for the ERCOT Interconnection may have to be adjusted when the annual review is performed in the fall of 2013. Efforts will also be made to mitigate problems with the wind energy dynamic models in the ERCOT case before analysis is performed.

Eastern Interconnection

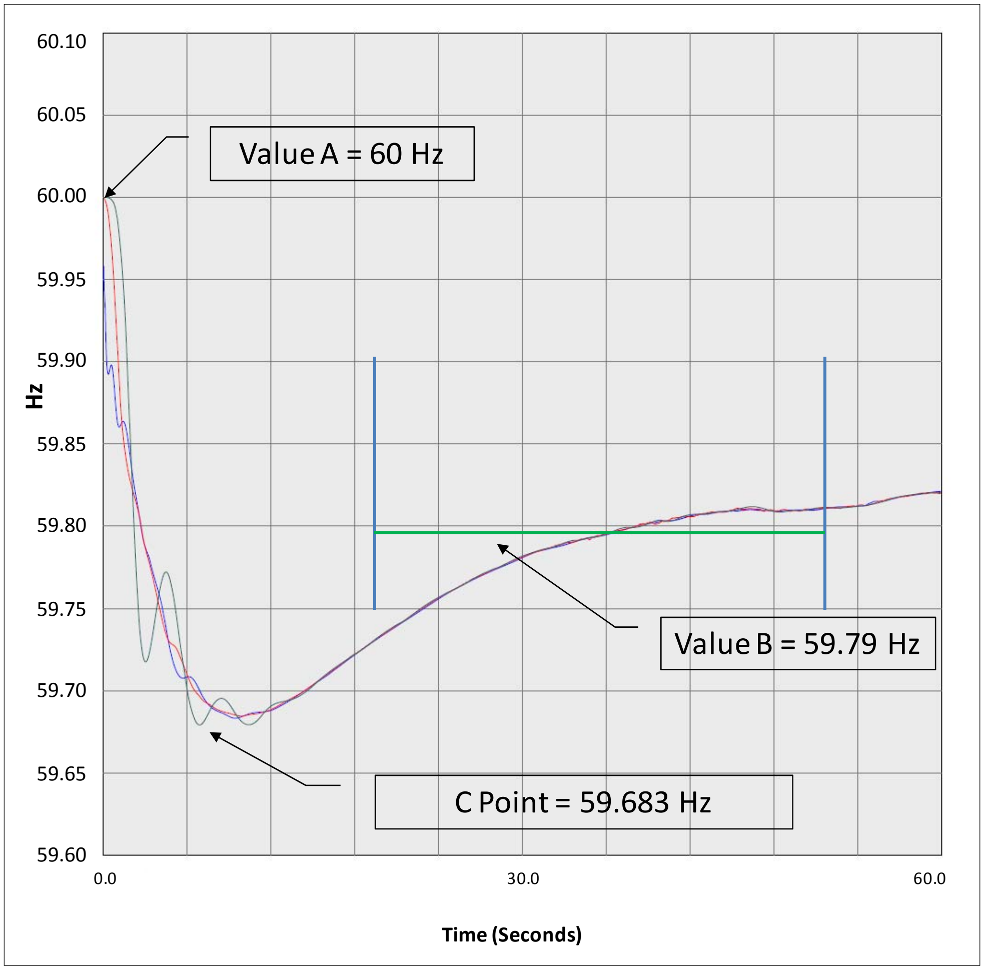
The IFRO for the Eastern Interconnection could not be reliably simulated with dynamics at this time because the dynamic models for the interconnection are not yet accurate enough to confidently predict system frequency response performance. The Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) has agreed to prepare an updated "generic governor" 2013 summer light load case (from the 2012 case series) for evaluating Eastern Interconnection IFROs by August 1, 2013. That case will use generic governor models to mimic the frequency response performance characteristics determined in the "Analysis of Eastern Interconnection Frequency Response" report published in March 2012. ERAG Management Committee is targeting completion of the governor review and case creation by August 1, 2014.

Western Interconnection Test

Initial Test

The WECC 2012-13 LW2 (light winter) operating case was utilized for the simulations (with minor data changes). The resource contingency tested was the tripping of two Palo Verde generating units, 2,740 MW total, as prescribe in Table B.

Figure 1: Initial WECC Simulation Test



The initial simulation shown in Figure 1 indicated an inherent frequency response 1,300 MW/0.1 Hz in the case as dispatched.

Value A[6] = 60.0 Hz
Value B[7] = 59.790 Hz
Point C = 59.683 Hz

[6] Value A frequency averaging period is T-16 through T+0 seconds
[7] Value B frequency averaging period isT+20 through T+52 seconds

CB_R = (60 – 59.683) / (60 – 59.790) = 1.51

Delta Frequency = 60 Hz – 59.790 Hz = 0.210 Hz

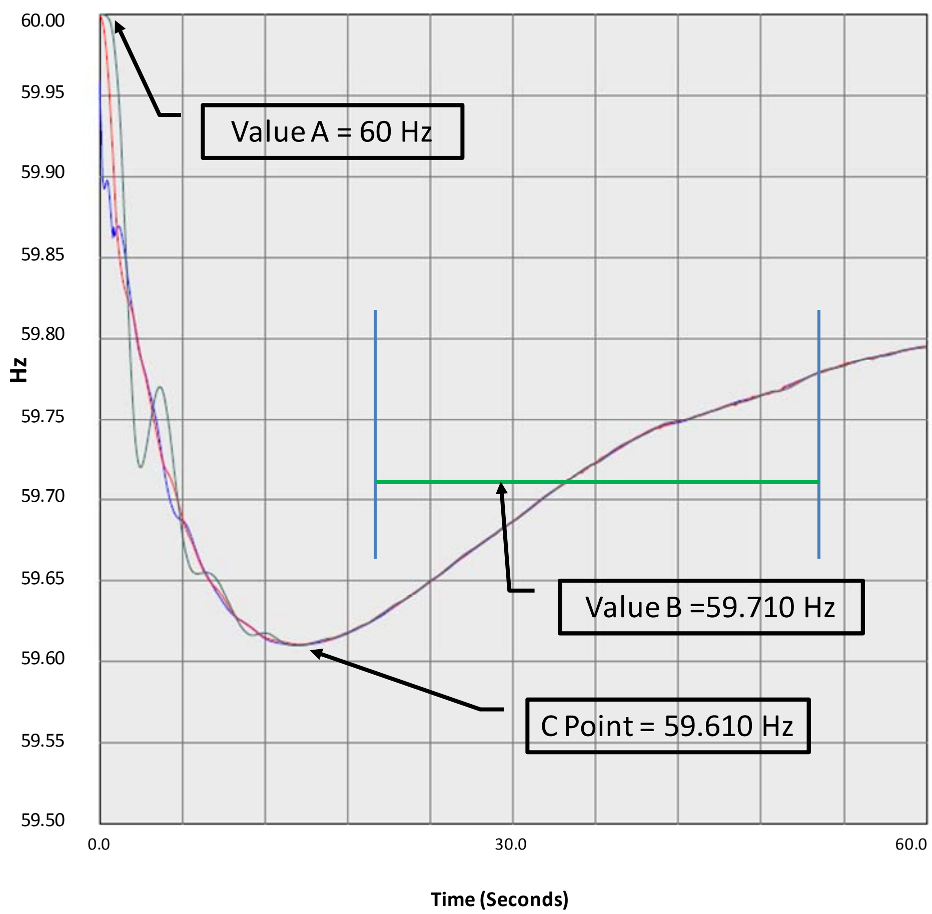
Delta $Frequency_{AC}$ = 60 Hz – 59.683 Hz = 0.317 Hz

Frequency Response = 2,740 MW / 0.21 Hz = 1,300 MW/0.1 Hz

IFRO Test

The frequency response for the initial case for WECC was well in excess of the IFRO of 840 MW/0.1 Hz. Therefore, in order to test the system at the prescribed response level, the frequency response of the case was de-tuned by reducing the response capabilities of some generation throughout the interconnection.

Figure 2: WECC IFRO Simulation Test



Value A[8] = 60.0 Hz
Value B[9] = 59.710 Hz
Point C = 59.610 Hz

[8] Value A frequency averaging period is T-16 through T+0 seconds
[9] Value B frequency averaging period isT+20 through T+52 seconds

CB_R = (60 – 59.610) / (60 – 59.710) = 1.34

Delta $Frequency_{AB}$ = 60 Hz – 59.710 Hz = 0.290 Hz

Delta $Frequency_{AC}$ = 60 Hz – 59.610 Hz = 0.390 Hz

Frequency Response = (2,740 – 300 MW) / 0.29 Hz = 840 MW/0.1 Hz

The resultant frequency response of 840 MW/0.1 Hz is virtually the same as the prescribed IFRO of 840 MW/0.1 Hz calculated in the Frequency Response Initiative report, and it matched the maximum delta frequency of 0.291 Hz.

Findings

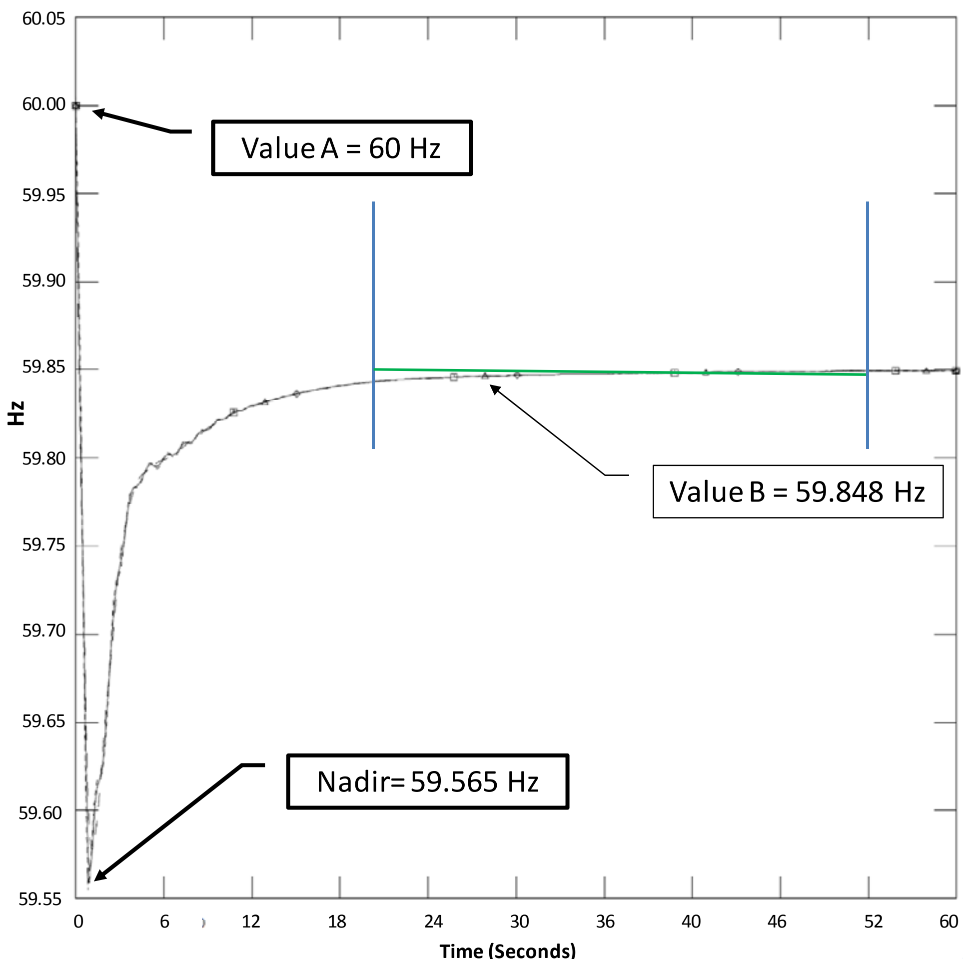
The dynamic simulation testing of the Western Interconnection IFRO indicated that the frequency nadir remains sufficiently above the UFLS threshold of 59.5 Hz with the prescribed 840 MW/0.1 Hz IFRO.

ERCOT Interconnection Test

The ERCOT 2011-12 winter off-peak base case was used for the simulations. For this analysis, it was found that the dynamics models for wind turbines were unstable over the period of the study (60 seconds). Since the wind turbines are not generally expected to supply primary frequency response for resource contingencies at this time, all wind turbine dynamics were removed from the case and the wind generators were “load netted” for the testing.

The resource contingency tested was the tripping of the two generating units at the South Texas Project Electric Generating Station, total net generation of 2,750 MW as prescribed in Table B, coupled with the tripping of Demand Resources of 1,300 MW at 59.7 Hz.

Figure 3: Initial ERCOT Simulation Test



The initial simulation shown in Figure 3 indicated an inherent frequency response 954 MW/0.1 Hz in the case as dispatched.

Value A[10] = 60.0 Hz
Value B[11] = 59.848 Hz
Point C = 59.565 Hz

CB_R = (60 – 59.565) / (60 – 59.848) = 2.86

Delta Frequency_{AB} = 60 Hz – 59.848 Hz = 0.152 Hz

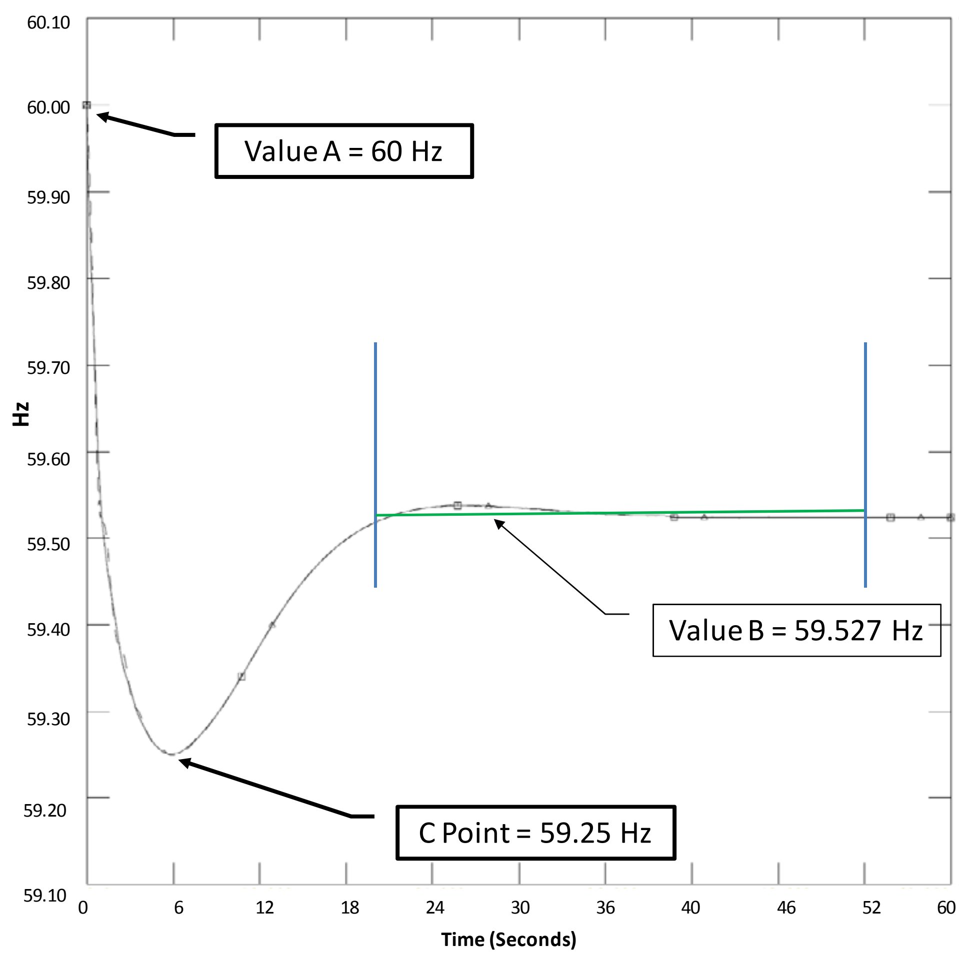
Delta Frequency_{AC} = 60 Hz – 59.565 Hz = 0.435 Hz

Frequency Response = (2,750 – 1,300 MW) / 0.152 Hz = 954 MW/0.1 Hz

IFRO Test

The frequency response for the initial case for ERCOT was well in excess of the prescribed IFRO of 286 MW/0.1 Hz. Therefore, in order to test the system closer to the prescribed response level, the frequency response of the case was de-tuned by reducing the response capabilities of some generation throughout the interconnection.

Figure 4: ERCOT IFRO Simulation Test



[10] Value A frequency averaging period is T-16 through T+0 seconds
[11] Value B frequency averaging period isT+20 through T+52 seconds

Value A[12] = 60.0 Hz
Value B[13] = 59.527 Hz
Point C = 59.250 Hz

CB_R = (60 – 59.250) / (60 – 59.527) = 1.59

Delta $Frequency_{AB}$ = 60 Hz – 59.527 Hz = 0.473 Hz

Delta $Frequency_{AC}$ = 60 Hz – 59.250 Hz = 0.750 Hz

Frequency Response = (2,750 – 1,300 MW) / 0.473 Hz = 307 MW/0.1 Hz

Estimation of necessary IFRO to avoid the 59.3 Hz UFLS top setting:

350 MW/0.1 Hz = 307 MW/0.1 Hz*(60 – 59.25) Hz / (59.963 – 0.012 – 59.3) Hz

Since the frequency nadir (point C) of 59.25 Hz is below the UFLS threshold of 59.3 Hz, a higher interconnection frequency response (approximately 350 MW/0.1 Hz) is needed to keep the frequency nadir sufficiently above the UFLS threshold of 59.3 Hz.

Findings

The IFRO for the ERCOT Interconnection may have to be adjusted when the annual review is performed in the fall of 2013. Efforts will also be made to mitigate problems with the wind energy dynamic models in the ERCOT case before analysis is performed.

[12] Value A frequency averaging period is T-16 through T+0 seconds.
[13] Value B frequency averaging period isT+20 through T+52 seconds.

Eastern Interconnection Test

The same level of simulations conducted for the Western and ERCOT Interconnections were not possible for the Eastern Interconnection because the dynamic models for the interconnection are not yet accurate enough to confidently predict system frequency response performance.

As stated in the Frequency Response Initiative report, NERC collaborated with the ERAG MMWG to perform an analysis of the modeling of overall frequency response in the Eastern Interconnection as part of the NERC Frequency Response Initiative and the Modeling Improvements Initiative. That review was a prelude to a plan for thorough examination of the governor models in the Eastern Interconnection dynamics study cases that are assembled by the MMWG. That report stated, "The turbine-governor modeling currently reflected in the MMWG dynamics simulation database is not a valid representation of the frequency control behavior of the Eastern Interconnection."

That project created a "generic case" dynamics model, replacing the turbine governor models in the case with generic governor models in order to ascertain the basic characteristics of the frequency response of the Eastern Interconnection. A simulation was made of a 4,500 MW resource loss event that occurred on August 4, 2007.

Figure 5: Comparison of Legacy and Generic Simulations to August 4 Event

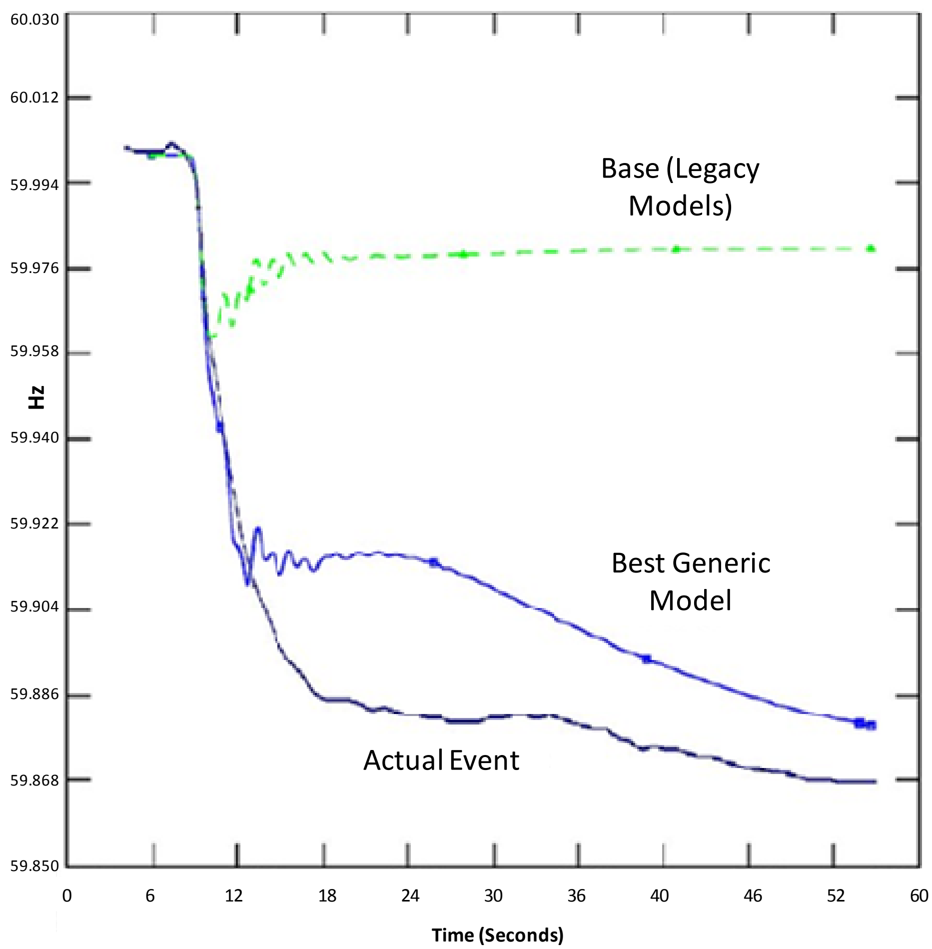


Figure 5 shows a comparison of the actual event frequency data and the simulations using both the original governor data (Legacy Models) and the generic case. The 4,500 MW resource loss event is the basis for the recommended resource loss event used in the Frequency Response Initiative report to calculate the prescribed Eastern Interconnection IFRO. Work is still underway to improve the dynamic models of the interconnection.

Findings

The IFRO for the Eastern Interconnection could not be reliably simulated with dynamics at this time because the dynamic models for the Eastern Interconnection are not yet accurate enough to confidently predict system frequency response performance. The ERAG MMWG has agreed to prepare an updated "generic governor" 2013 summer light load case (from the 2012 case series) for evaluating Eastern Interconnection IFROs by August 1, 2013. That case will use generic governor models to mimic the frequency response performance characteristics determined in the "Analysis of Eastern Interconnection Frequency Response" report published in March 2012. The ERAG Management Committee is targeting completion of the governor review and case creation by August 1, 2014.

Exhibit I

Consideration of Comments

Project 2007-12
Frequency Response

Related Files

Status:
The standard will be presented to the NERC Board of Trustees for adoption at its February meeting and if adopted, filed with regulators for approval.

Purpose / Industry Need:
Frequency Response, a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load, is a critical component to the reliable operation of the bulk power system, particularly during disturbances and restoration. Failure to maintain frequency can disrupt the operation of equipment and initiate disconnection of power plant equipment to prevent them from being damaged, which could lead to wide-spread blackouts. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard would set a minimum Frequency Response obligation for each Balancing Authority, provide a uniform calculation of Frequency Response and Frequency Bias Settings that transition to values closer to natural Frequency Response, and encourage coordinated AGC operation.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 **BAL-003-1** Clean | Redline to Last Posting **Attachment A** Clean | Redline to Last Posting **Implementation Plan** Clean | Redline to Last Posting	Recirculation Ballot Info>> Vote>>	12/12/12 - 12/21/12 (closed)	Summary>> Full Record>>	

Supporting Materials: **Procedure** Clean | Redline to Last Posting **Background Document** Clean | Redline to Last Posting Mapping Document VRFs and VSLs Frequency Response Initiative Report **FRS Form 1:** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection **Excel 97 - 2003 Version** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection **FRS Form 2:** Multiple BA Interconnection (Eastern & Western)				

ERCOT Quebec Interconnection **Excel 97 - 2003 Version** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection				
Draft 3 **BAL-003-1** Clean | Redline to Last Posting **Attachment A** Clean **Implementation Plan** Clean | Redline to Last Posting **Supporting Materials:** Procedure Background Document BAL-003-0.1b Unofficial Comment Form (Word) Updated 10/16/12) **Mapping Document** Clean | Redline to Last	Successive Ballot and Non-Binding Poll Updated Info>> Info>> Vote>>	10/26/12 - 11/06/12 (Closed)	Summary>> Full Record>> Non-binding Poll Results>>	
	Comment Period Info>> Submit Comments>>	10/05/12 - 11/06/12 (Closed)	Comments Received>>	Consideration of Comments **6**

Posting **VRF/VSL** Clean/Redline to Last Posting **FRS Form 1:** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection **Excel 97 - 2003 Version** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection **FRS Form 2:** Multiple BA Interconnection (Eastern & Western) ERCOT Quebec Interconnection **Excel 97 - 2003 Version** Multiple BA Interconnection (Eastern & Western)				

ERCOT Quebec Interconnection				
Frequency Response Technical Conferences Unofficial Comment Form (Word)	Informal Comment Info>> Submit Comments>>	05/30/12 - 06/15/12 (closed)	Comments Received>>	
Draft 2 **BAL-003-1** Clean | Redline to Last Posting **Attachment A** Clean **Attachment B** Clean **Implementation Plan** Clean | Redline to Last Posting **Supporting Materials:** Background Document BAL-003-0.1b Comment Form (Word) Mapping Document	Initial Ballot and Non-Binding Poll of VRFs and VSLs Vote>> Info>>	11/30/11 - 12/09/11 (closed)	Summary>> Full Record>> Non-Binding Poll Results>>	
	Formal Comment Period Info>> Submit Comments>>	10/25/11 - 12/09/11 (closed)	Comments Received>>	Consideration of Comments **5**
	Join Ballot Pool Initial and Non-Binding Info>> Join>>	10/25/11 - 11/23/11 (closed)		

FRS Form 1: Eastern Interconnection ERCOT Quebec Interconnection Western Interconnection **FRS Form 2 for Interconnection with Multiple BAs:** Two-second Sample Data Three-second Sample Data Four-second Sample Data Five-second Sample Data Six-second Sample Data **FRS Form 2 for Interconnection wit One BA:** Two-second Sample Data Three-second Sample Data				

Draft 1 BAL-003-1 Clean Attachment A **Supporting Materials:** BAL-003-0 Supplemental SAR FRS Form 1 Instructions FRS Form 1 Implementation Plan Comment Form (Word) Field Test	Formal Comment Period Info>> Submit Comments>>	02/04/11 – 03/07/11	Comments Received>>	Consideration of Comments **4**
Final SAR Version 3	Standard Drafting Team Nominations Info>> Submit Nomination>>	07/17/07 - 07/30/07 (closed)		
Draft 3 Frequency Response SAR Draft SAR Version 3	Comment Period Info>> Submit	02/08/07 - 03/09/07 (closed)	Comments Received>>	Consideration of Comments **3**

	Comments>>			
Draft 2 Frequency Response SAR Draft SAR Version 2	Comment Period Info>> Submit Comments>>	04/04/06 - 05/03/06 (closed)	Comments Received>>	Consideration of Comments **2**
Draft 1 Draft SAR Version 1 White Paper		01/17/05 - 02/17/05 (closed)	Comments Received>>	Consideration of Comments **1**

Background:

The Frequency Response SAR drafting team thanks all commenters who submitted comments on the first draft of the Frequency Response SAR. The SAR was posted for comment from January 17 – February 17, 2005. The SAR drafting team asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 30 sets of comments.

Based on the comments received, the drafting team has revised the SAR and is reposting it for an additional 30-day comment period

In this 'Consideration of Comments' document, stakeholder comments have been organized so that it is easier to see the summary of changes being requested of the SAR. All comments received on the first draft of the Frequency Response SAR can be viewed in their original format at:

ftp://www.nerc.com/pub/sys/all_updl/standards/sar/Frequency_Response_SAR_Comments_02_17_05.pdf

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

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments and Responses:

1. Do you agree there is a reliability need for specifying the quality and quantity of frequency response?

Summary Consideration: Most commenters agreed that there is a reliability need to specify the quality and quantity of frequency response.

Commenter	Yes	No	Comment
MAAC Staff (2) Al DiCaprio – MAAC (2) Joe Willson – MAAC (2) Mark Kuras – MAAC (2)		✓	There is a need for governors but not for frequency response. Governors are needed to resynchronize during restoration. But the need for a short-term frequency response characteristic has been obviated by the pending Version1 Balancing Standard. That standard is designed to ensure that interconnection frequency is never at such a level that the loss of the largest contingency will cause instability or cascading outages. If the system is always in such a state why would the instantaneous response to the loss of a single contingency add to the system reliability? The SAR has not provided any definitive need. The SAR has not provided sufficient focus vis-à-vis who is responsible to meet the standard (the generator, the BA, the Load, the RA) This proposal has not provided any additional information concerning the need for this proposed Standard since the last time (during the Balancing Resources and Demand consensus) that a similar Frequency Response Requirement was overwhelming rejected by those who commented to that proposal. Transient frequency response has not been the target of any major public concern. The current Version 1 Control Standard proposal provides limits on the frequency excursions that can be controlled by system-operators and their control systems. Relays and other Protection Devices serve to protect those time frames too short for an operator to respond to. What does this standard add? **Comments** This SAR is not clear as to what it really is intended to mandate. Does the requestor want to create a standard for Generator Owners to install governors? Or a standard on Generator Operators for individuals unit governor response? Or a standard for Balancing Authorities for Area response? Or for Reliability Authorities for Regional response? All of these are different requirements and have different effects. The requestor must be clear as to what is intended. To ensure that frequency doesn't hit a relay limit (as in the Balancing standard?) or is it to address the need for governors when synchronizing? When does the standard apply? All times (which means that NERC can go to a unit, BA or RA to check that some finite response is available?) Just at times when large events occur (the problem is of course whether or not the outage is near or far from the entity being checked)? Only during test conditions (since a unit under stress – 'valves wide open' has not governor response at that time – even though it may have the greatest of

Commenter	Yes	No	Comment
			responses at other times). The requestor's intent may be laudable but the description is no where near ready to be considered as 'standard material'.
Response: The drafting team (Resources Subcommittee Frequency Task Force) attempted to answer many of the questions raised by the commenters in the Frequency Response Standard Whitepaper. We agree that the standard needs to be clear to who and when it would apply and this is addressed in the revised SAR. While the Interconnections may have sufficient frequency response for normal operations, we don't know how this response is dispersed and at what point it will pose a reliability risk. A primary purpose of this standard is to collect information so informed decisions can be made before there is a problem. We disagree that the Balance Resources and Demand (BRD) standard is sufficient for all operating states. The BRD addresses steady state and fully interconnected conditions. Refer to "A New Thermal Governor Modeling Approach in the WECC" by Les Pereira, John Undrill, Dmitry Kosterev, Donald Davies, and Shawn Patterson. Also, keep in mind that response has continued to decline since the last published study, even though it should be increasing with load growth. As you request, the draft standard addresses who is required to meet the standard (BA). The standard will be designed such that a BA can mirror the metrics within its boundaries (evaluate generators and LSEs) if they so choose. The standard is not intended to establish a large set of arbitrary requirements, but will establish the framework to collect the information to make informed engineering decisions. The revised SAR clarifies what is expected.			
BPA Bart McManus Brian Tuck James Randall Francis Halpin Bill Mittlestat James Murphy		✓	NERC should not involve itself in the development of these standards and should allow individual interconnections to address frequency response issues independently. For example, the WECC is currently working on standards that will address this concern. They will be tailored to the specific requirements of this interconnection and will provide the best possible solution to the problem. There may be a need to specify frequency response requirements within some interconnections; however, it is not necessary, or most effective for them to be defined at the NERC level.
Response: The Resources Subcommittee Frequency Task Force agrees that frequency response is primarily an Interconnection issue and, as envisioned, the proposed standard would accommodate Interconnection differences both in amounts of response and methodology in calculating response. The standard would identify technical and engineering principles that should be met to calculate and evaluate the amount and distribution of frequency response within each Interconnection. The drafting team believes that stakeholders would prefer the assurance of knowing that NERC is providing oversight to ensure that all Interconnections have a technically sound basis for the development of respective frequency response requirements.			
FRCC (2) Linda Campbell Ron Donahey – TEC (1) Mark Bennett – GRU (3) Steve Wallace – SEC (5) S. McElhaney – FMPA (5) Ted Hobson – JEA (1)		✓	The FRCC does not support the development of a Frequency Response Standard at this time. A standard for each Interconnection, although informative would be unenforceable as far as identifying short term, frequency response deficient, entities or areas. As such measurability and compliance by the relevant entities would be all but impossible. As far as an Interconnection allocation program for frequency response, we feel that the "apparent" decline in response is not significant enough to warrant a standard at this time and we would require additional details of how such a plan would be implemented and the potential economic impacts on the Regions that would be

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>associated with that plan.</td></tr>
<tr><td colspan="4">Response: The standard as envisioned does not mandate a specific amount of frequency response. With regard to the “apparent” decline in frequency response, the most widely published report (Ingleson and Nagle, 1999) documented a change in Eastern Interconnection response from 3750MW/0.1Hz in 1994 to 3390MW/0.1Hz in 1998. The Resources Subcommittee evaluation of 44 events in 2005 showed an average frequency response well below 3000MW/0.1Hz. Theoretically, response should be increasing over time with increasing load and generation in an Interconnection. One of the primary reasons for the standard is to enable a better analysis of response and also enable informed decisions. As envisioned, the standard will provide a fairly simple methodology to verify compliance.</td></tr>
<tr><td>ISO/RTO Standards Review Committee (2)
K. Tammar – NYISO (2)
D. McMaster – AESO (2)
Ed Riley – CAISO (2)
Sam Jones – ERCOT (2)
P. Henderson – IESO (2)
P. Brandien – ISO-NE (2)
B. Phillips – MISO (2)
B. Balmat – PJM (2)
C. Yeung – SPP (2)</td><td>✓</td><td>✓</td><td>We agree in general that there is a reliability need to have frequency response, particularly during disturbances, islanding and restoration. The standard should provide the process for a technically sound calculation of frequency response and bias (both fixed and variable).

Any new standards on frequency response need not and should not be onerous by finding BAs noncompliant with response less than average or below some un-validated norms.

If performance is significantly less than an Interconnection norm, the standard should not trigger an automatic non-compliance. In these situations the BA should perform an internal review/assessment that ensures governors are working as designed, that the BA knows which resources are frequency responsive (so the information can be included in restoration plans), whether governors can be triggered to be more responsive during disturbances, etc and satisfy the Interconnection requirement. If the Interconnection requirement is not met within a reasonable timeframe then the BA should be deemed as non-compliant.

When required, the validation of governor performance could be achieved either through online monitoring in an EMS or periodic testing (both methods should be explained in a reference document to support the standard).

The standard should acknowledge that some units might not provide response under normal operations (e.g. nuclear units operating at full load) and that response is highly variable event-to-event based on simultaneous load changes.

The standard should acknowledge the differing Interconnection requirements (smaller Interconnections need greater response).

The standard should also track Interconnection and BA areas response over time (years) and be reevaluated as performance changes.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. As envisioned, the standard would not mandate a given amount of response, but would require</td></tr>
</table>

Commenter	Yes	No	Comment
an analysis if response were measurably below the norm (this detail has been added to the detailed description in the SAR). There is another standard under development, (Phase III & IV MOD-027 - Verification and Status of Generator Frequency Response) that requires Generator Owners to verify that their governors are working as designed. The standard would accommodate the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee Frequency Task Force has a tool that could calculate the BA's performance to the standard. The SAR was also changed to reflect the suggestions to accommodate: • Both fixed and variable bias. • Cases where a specific unit (e.g. nuclear) is prohibited from providing frequency response. • Differing Interconnection needs.			
CAISO (2) Ed Riley Yuri Makarov Steve McCoy	✓		Frequency response provided by speed governors and loads helps to prevent load shedding and generator trips at significant frequency excursions caused by sudden active power mismatches in the systems. Without a sufficient frequency response emerging during the first seconds after a frequency disturbance, there is a danger of further cascading development or frequency instability and system collapse cased by underfrequency generator trips. It has been already noted that insufficient frequency response in some parts of an Interconnection may cause certain temporary redistribution of power flows and reduce stability margins after frequency disturbances that may limit the OTC on critical paths within the Interconnection. It has been also observed that insufficient frequency response may cause a weaker frequency recovery that bears a greater risk of system collapse at subsequent frequency disturbances. Therefore, frequency response is definitely a reliability issue that needs to be addressed by a NERC standard.
Response: The Resources Subcommittee Frequency Task Force agrees that there are several issues that must be addressed in the standard or in supporting business practices. As envisioned, the proposed standard would not be prescriptive with regard to "how much" and "where" the response is carried.			
Manitoba Hydro (1, 3, 5, 6) Gerald Rheault	✓		Manitoba Hydro , from a reliability perspective, supports the idea of specifying the quantity and quality of frequency response and incorporating these elements in a Standard. However, the development of this standard should not be rushed since the evidence provided in the Standard Authorization Request form and in the Frequency Response Standard White paper shows that current frequency response and projected frequency response trends do not pose a significant potential for compromising system reliability and for major under-frequency load shedding to occur in the near term. Also in the section of the white paper which examines "frequency response standard considerations", a broad scope and outline is given, more detail is required especially regarding methods of ensuring compliance. In paragraph 2, page 9 of the white paper where the current frequency response of the Eastern Interconnection is stated as 3100 MW/0.1 Hz with a standard deviation of 1870 MW/0.1 Hz and the statement is made that "the fact that an under-frequency

Commenter	Yes	No	Comment
			event has not happened yet is only coincidence" requires much more detailed information regarding the origin and calculations of these numbers before these assumptions can be made. Could it be that instead of a frequency response closer to 1230MW/ 0.1 Hz it is actually practically closer to 3100 MW/ 0.1 Hz or even 4970 MW/ 0.1 Hz most of the time? One understandable major concern addressed in the white paper is the response of combined-cycle units to frequency decline and the fact that due to a drop in combustion air volume their output may actually decrease with a drop in frequency or even result in unit tripping. Also there was concern with the possibility that larger amounts of these types of units will be installed on the system thereby potentially increasing the decline in frequency response rate from 70 MW/ 0.1 Hz /Year (Eastern Interconnection) . It is also mentioned (on page 10) that with proper tuning combined cycle units can provide correct frequency response. Maybe part of the focus should be on finding ways of enforcing the Current Requirements (Page 14) and including specific frequency response requirements for combined-cycle units.
Response: The Resources Subcommittee Frequency Task Force agrees that the standard should not rush to a decision on the amount and location of frequency response, but should set the framework for making informed decisions. Frequency response is needed for more than protection against UFLS. Response is also needed during disturbances and restoration. With regard to "current requirements", the Whitepaper listed what existed in NERC Policy, mostly as guides. There is very little in the V0 Standards regarding governors or frequency response. We agree that the standard should not impose unreasonable costs to demonstrate compliance. We agree that frequency response should be monitored both at the BA and Interconnection level. Characterizing how frequency response changes under varying interconnection load and unit commitment conditions will be addressed by a sampling methodology. The drafting team is pursuing the addition of functionality in the "NERC –ACE monitoring application" that will identify generator trips and automate the calculation of Interconnection frequency response. Evidence to date indicates that frequency response declines significantly during light load periods, even though the exact mechanism for this is not well defined. Most of the major frequency excursions experienced in the Eastern Interconnection have occurred during the shoulder period of the year during either the early morning or late evening periods. Regarding the last comment, there currently are no governor or frequency response requirements for generators.			
Energy Mark, Inc. (8) Howard Illian	✓		There is a reliability need but it is not an immediate reliability need for all of the interconnections. The amount of Frequency Response on the Texas Interconnection is close to the minimum acceptable amount, and therefore, there is an immediate need for a FRS on the Texas Interconnection. On the Western Interconnection, the WECC keeps close tabs on Frequency Response and takes immediate action when a problem arises with frequency response on that interconnection. Although there is no immediate need for a Frequency Response Standard on the Western Interconnection at this time, the observed reductions in Frequency Response on that interconnection make this issue an ongoing concern. Finally, there is no current need for a Frequency Response Standard on the Eastern Interconnection because current Frequency Response is adequate. However, it

Commenter	Yes	No	Comment
			takes significant time to develop an effective standard and put it in place. The Balancing Resources and Demand Standard is entering its fourth year of development with expectations of at least another year before implementation. A Frequency Response Standard would be expected to take a similar period to develop. That means that it will be at least 2010 before a new FRS would be put in place. There is no question that adequate Frequency Response is required for reliability. There is no question that Frequency Response on the Eastern Interconnection is declining. There are two paths of action available; 1) Wait until adequate Frequency Response causes reliability problems and then begin the five year process to develop a standard; 2) Begin development of a FRS and determine the final need for implementation during the five year development process. I would rather have a standard that requires measurement that does not result in enforcement action, and therefore, has no effect on operations, than not have a standard when there are definite reliability problems. It will be much easier to implement a standard for Frequency Response before reliability problems occur than to implement a standard after reliability problems occur. NERC should develop a Frequency Response Standard and continue to investigate the need for the standard during its development.
Response: The Resources Subcommittee Frequency Task Force agrees with the comments that the standard should initially focus on measuring the amount of response and not impose restrictions on current operations. As envisioned, the proposed standard would identify a consistent, objective calculation of frequency response The standard would require regional and local analyses when BAs have low response. This way, informed technical decisions can be made prior to reaching a point where reliability is truly threatened.			
MAAC (2) John Horakh	✓		There may be a reliability need in the near future. The white paper does an excellent job of making that case. For the purpose of commenting on a SAR that has not yet produced a proposed Standard, I can give it the benefit of the doubt and say yes, there is reliability need.
Response: The Resources Subcommittee Frequency Task Force appreciates your support and agrees that there is a reliability need for this proposed standard.			
MRO (2) Larry Larson – OTTP Al Boesch – NPPD Terry Bilke – MISO R. Coish – MH Dennis Florom – LES K. Goldsmith – Alliant Todd Gosnell – OPPD W. Guttormson – SaskPwr Jim Maenner – WPS Tom Mielnik –	✓		We agree (with qualifications). Any new standards on frequency response need not and should not be onerous (identifying BAs noncompliant with less than average response or some un-validated norms). The standard should provide the process for a sound calculation of frequency response and bias (both fixed and variable). There may be valid reasons why a BA is below observed norms in response. It may meet most of its obligations with schedules. Rather than generate an automatic non-compliance when response is below some benchmark, the standard should require

Commenter	Yes	No	Comment
MidAmerican Darrick Moe – WAPA Joe Knight – MRO			an internal review that ensures governors are working as designed, that the BA knows which resources are frequency responsive (so the information can be included in restoration plans), whether governors can be put in more responsive modes during disturbances, etc. The standard should have some requirements on generators if the BA is not providing the response outlined in the standard (governors should be working as designed). The standard should also track Interconnection response over time and identify a target response (different for each Interconnection). NERC or NAESB will want to look at how this is allocated to BAs and generators.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. As envisioned the proposed standard would not mandate a given amount of response, but would require an analysis if response is measurably below the norm. As envisioned the proposed standard is would acknowledge the variability inherent in measuring frequency response and would provide two methods of capturing sufficient samples to make an objective measurement. The standard would not preclude market solutions. The SAR detailed description has been expanded to state that the standard will include a sound calculation for measuring frequency response with consideration of interconnection specifics. Another detail added to the SAR requires generator units with nameplate ratings of 10 MW or greater to be equipped with governors. There is another standard under development, (Phase III & IV MOD-027 - Verification and Status of Generator Frequency Response) that requires Generator Owners to verify that their governors are working as designed. Finally, the SAR was modified to accommodate both fixed and variable bias.			
Southern Company Transmission, Operations, Planning and EMS Divisions (1) Marc Butts Steve Corbin Jim Viikinsalo Jim Griffith Doug McLaughlin Monroe Landrum	✓		Trends in Eastern and Western Interconnection Turbine Governor Response and primary frequency response over the past two decades (as documented by EPRI Project RP2473-53 and Decline of Eastern Interconnection Frequency Response by Ingleson and Nagle) as well as trends in frequency error magnitude and variance over the past five years (as documented by the NERC Resources Subcommittee at URL http://www.nerc.com/~filez/rs.html) indicate that significant frequency response degradation is occurring, particularly in the Eastern Interconnection. While not yet a crisis, these trends are indicative of significant changes in design and operational practices on the interconnected electrical systems of North America which, if not managed intelligently, can cause significant degradation in reliability. We strongly urge the industry to support this SAR and begin the process of controlled management before the processes behind these trends reach crisis proportion.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
New York ISO (2) Mike Calimano	✓		We agree in general that there is a reliability need to have frequency response, particularly during disturbances, islanding and restoration. The standard should provide the process for a technically sound calculation of frequency response and bias (both fixed and variable). Any new standards on frequency response need not and should

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>not be onerous by finding BAs noncompliant with response less than average or below some un-validated norms. There may be valid reasons why a BA is below observed norms in response. For example, the BA may meet most of its obligations with schedules or its native load may be non-responsive.

If performance is significantly less than an Interconnection norm, the standard should not trigger an automatic non-compliance. In these situations the BA should perform an internal review/assessment that ensures governors are working as designed, that the BA knows which resources are frequency responsive (so the information can be included in restoration plans), whether governors can be put in more responsive modes during disturbances, etc.

When required, the validation of governor performance could be achieved either through online monitoring in an EMS or periodic testing (both methods should be explained in a reference document to support the standard).

The standard should acknowledge that some units might not provide response under normal operations (e.g. nuclear units operating at full load) and that response is highly variable event-to-event based on simultaneous load changes. The standard should acknowledge the differing Interconnection requirements (smaller Interconnections need greater response).

The standard should also track Interconnection response over time (years) and be reevaluated as performance changes.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. As envisioned, the standard would not mandate a given amount of response, but would require an analysis if response were measurably below the norm (this detail has been added to the detailed description in the SAR).

There is another standard under development, (Phase III & IV MOD-027 - Verification and Status of Generator Frequency Response) that requires Generator Owners to verify that their governors are working as designed.

The standard would accommodate the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee Frequency Task Force has a tool that could calculate the BA's performance to the standard.

The SAR was also changed to reflect the suggestions to accommodate:
• Cases where a specific unit (e.g. nuclear) is prohibited from providing frequency response.
• Differing Interconnection needs.</td></tr>
<tr><td>IESO (2)
Pete Henderson</td><td>✓</td><td></td><td>We agree in general that there is a reliability need to have frequency response, in order to maintain interconnection frequency and particularly during disturbances, islanding and restoration. The standard need to address both the system needs as well as island requirements for frequency response.

The standard should provide the process for a technically sound</td></tr>
</table>

Commenter	Yes	No	Comment
			calculation of frequency response and bias. The standard should acknowledge that some units might not provide response under normal operations (e.g. nuclear units operating at full load) and that load response is highly variable event based on time of day or year. The standard should acknowledge smaller areas need greater response. Where BA areas are deficient in meeting the interconnection requirement , they should be allowed a reasonable period of time to take appropriate steps to make corrections before being assessed as non compliant. The standard should also track area response over time (years) and be reevaluated as performance changes. Quality should be defined. For generators it should include dead-band, droop characteristics, etc.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. As envisioned, the standard would not mandate a given amount of response, but would require an analysis if response were measurably below the norm (this detail has been added to the detailed description). The standard accommodates the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee Frequency Task Force has a tool that will calculate the BA's performance to the standard. The Resources Subcommittee Frequency Task Force agrees with your "governor quality" comment and has added governor installation and operation details to the SAR's detailed description. As envisioned, the standard will provide the Balancing Authority with sub-par frequency response time to analyze their situation and make necessary changes and corrections.			
ATC (1) Peter Burke	✓		Based on the NERC white paper Frequency Response Standard Whitepaper dated April 6, 2004 that was prepared by the Frequency task Force of the NERC Resources Subcommittee, it would appear that the decline in frequency response of both the Eastern and Western Interconnections is a reliability concern. As a transmission provider, however, there is probably little that can be done other than make sure that governor response and load modeling can be made as accurate as reasonably possible in conducting dynamic simulations and be aware of this issue in studying existing as well as new generating facilities. The control area, generation operators and turbine-generator manufacturers need guidance provided as to their responsibilities and obligations regarding frequency response. Changes in the load characteristics (e.g. fewer large motors, variable speed drives, etc) over time, plus changes in reserve sharing practices brought on by deregulation and competition are and will affect load response to frequency excursions. The type of generation (e.g. combustion turbine units, combined-cycle units) being interconnected to the system as well as the operation of the

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>governors (e.g. blocked or improper settings) and turbines (e.g. sliding pressure, boiler-follower, etc.) of existing generators have a significant effect on the system frequency response.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees with your technical comments in support of this standard. The team also supports the development of the planning “MOD” standards that address frequency response at the generator level.</td></tr>
<tr><td>NERC Frequency Task Force
Raymond L. Vice, Chairman</td><td>✓</td><td></td><td>Trends in Eastern and Western Interconnection Turbine Governor Response and primary frequency response over the past two decades (as documented by EPRI Project RP2473-53 and Decline of Eastern Interconnection Frequency Response by Ingleson and Nagle) as well as trends in frequency error magnitude and variance over the past five years (as documented by the NERC Resources Subcommittee at URL http://www.nerc.com/~filez/rs.html) indicate that significant frequency response degradation is occurring, particularly in the Eastern Interconnection. While not yet a crisis, these trends are indicative of significant changes in design and operational practices on the interconnected electrical systems of North America which, if not managed intelligently, can cause significant degradation in reliability. I strongly urge the industry to support this SAR and begin the process of controlled management before the processes behind these trends reach crisis proportion.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees with these comments.</td></tr>
<tr><td>Robert Blohm</td><td>✓</td><td></td><td>The CPS1 equation is a single equation in two variables, primary (governor) response and secondary response. Two variables require two equations in order to have a unique solution. That second equation does not currently exist and must be the proposed Frequency Response standard that pins down the value of primary (governor) response. Currently, the single CPS1 equation allows any Balancing Authority an infinity of solutions for any given CPS1 value. Accordingly, Balancing Authorities have been tending to reduce expensive primary response and increase cheaper secondary response (AGC, regulation, load following) to achieve a given CPS1 score, which is an average over time. The result has been a halving of system bias in the Eastern</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force appreciates your comment and your support for the frequency response standard.</td></tr>
<tr><td>SPP Operating Reliability Working Group
Robert Rhodes –SPP (2)
Ron Ciesiel – SPP (2)
Bob Cochran – SPS (1)
Mike Gammon – KCPL (1)
Steve Hillman – WPEK (1)
Allen Klassen – Westar</td><td>✓</td><td></td><td>A frequency response standard is needed but only within the scope and range of the previously provided guides in Policy 1 such as a design criteria of 5% droop, a 36 mHz deadband with exclusions for nuclear, combined cycle and small generating units.</td></tr>
</table>

Commenter	Yes	No	Comment
(1) Bill Nolte – SECI (1) Mike Stafford – GRDA (1)			
Response: The Resources Subcommittee Frequency Task Force agrees with the comments and has added statements to the detailed description to reflect the comments. However, the SAR is intended to capture the scope of the standard and the specific parameters will be determined by the standard drafting team.			
Southern Co. Generation (6) Roman Carter Tony Reed Joel Dison Lucius Burris Lloyd Barnes Clifford Shepard Terry Crawley Roger Green Tom Higgins	✓		Trends in Eastern and Western Interconnection Turbine Governor Response and primary frequency response over the past two decades (as documented by EPRI Project RP2473-53 and Decline of Eastern Interconnection Frequency Response by Ingleson and Nagle) as well as trends in frequency error magnitude and variance over the past five years (as documented by the NERC Resources Subcommittee at URL http://www.nerc.com/~filez/rs.html) indicate that frequency response degradation is occurring, particularly in the Eastern Interconnection. While not yet a crisis, these trends are indicative of significant changes in design and operational practices on the interconnected electrical systems of North America which, if not managed intelligently, can cause degradation in reliability. We support this SAR in an effort to begin the process of controlled management before the processes behind these trends reach crisis proportion.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
TXU Energy Delivery Roy Boyer	✓		Yes, I agree there is a reliability need for specifying the quality and quantity of frequency response. There is ample evidence that specifying a droop value or that specifying governors must be in operation will not necessarily result in any useful governor response to a sudden large drop in system frequency. So yes, I think a SAR team should look into this matter. I would suggest the part load can play in arresting frequency decline be included in the scope. I would also suggest that the frequency response needs of the regions will likely vary, so final specific requirements should probably be made at the region level.
Response: The Resources Subcommittee Frequency Task Force agrees that load can provide frequency response and load contribution is, by default, included in the balancing authority's performance. The standard is indifferent to whether response is provided by load or generation. The proposed standard recognizes the role and importance of both the Interconnection and the Regional Reliability Organization in the establishment of requirements. In general, it is expected there is a "base" Interconnection target response that will be addressed in this standard. Each Interconnection would have a different target, based on its size and historic response. There are areas (e.g. Maritimes) that require additional response. It is expected these unique situations will be primarily addressed in the "MOD" standards. This standard would enable improved data for the MOD standards.			
MISO Terry Bilke	✓		These are my individual comments as a member of the NERC Resources subcommittee and not those of representing any organization. There is a reliability need for a light-handed standard that allows us to do a better job of ensuring response is available when

Commenter	Yes	No	Comment
			required. As some entities might comment, there is adequate response in all interconnections during "system normal" conditions. The problem is what occurs during major disturbances and restoration. A primary reason the industry needs to do a better job of tracking frequency response is the fact that response is declining when it should actually be increasing with load and generation growth. The standard should not be structured such that it finds BAs noncompliant if response is below average or if response is low for a given event. Frequency response at the BA level is extremely variable as the measure is mingled with load fluctuation. The standard should guide a technically sound calculation of response at the BA level and track interconnection performance over time to enable informed decisions. If a BA performs significantly below an Interconnection norm, the standard should require the BA do an internal assessment of its key generation to verify governors are working as designed and that there will be frequency responsive resources for disturbances and restoration. If Interconnection response significantly changes over time, the standard should be reevaluated.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
TXU Electric Delivery (1) Travis Besier or Ellis Rankin	✓		TXU Electric Delivery proposes that Frequency Response Guidelines at the NERC level should only be in general terms and require that each Reliability Authority establish a specific Frequency Response Standard with detailed specifications as appropriate for its region.
Response: The Resources Subcommittee Frequency Task Force intent was not to mandate a specific amount of frequency response, but to require a consistent, objective calculation of frequency response. The balancing authority and the Regional Reliability Organization must do an assessment of adequacy if response is measurably below the norm. The proposed standard recognizes the role and importance of the Interconnection and the Regional Reliability Organization in the establishment of requirements. In general, it is expected there is a "base" Interconnection target response that will be addressed in this standard. Each Interconnection would have a different target, based on its size and historic response. There are areas (e.g. Maritimes) that require additional response. It is expected these unique situations will be primarily addressed in the "MOD" standards. This standard would enable improved data for the MOD standards.			
TVA (1) Kathie Davis Larry Akens Mitch Needham Chuck Feagans	✓		

Commenter	Yes	No	Comment
Ed Forsythe			
Alliant Energy (1) Kenneth A. Goldsmith	✓		
Progress Energy – Carolinas (1, 3, 5, 6) Phil Creech	✓		
Dick Schulz Chair, IEEE Task Force on Large Interconnected Power System Response to Generation Governing	✓		
NCPA (4) Les Pereira	✓		
NPCC CP9, Reliability Standards Working Group Guy V. Zito – NPCC (2) Ralph Rufrano – NYPA (1) K. Goodman – ISONE (2) Al Adamson – NYSRC (2) Bob Pelligrini – UI (1) D. Kiguel – Hydro One (1) P. Lebro – Nat'l Grid (1) R. Champagne – TE (1) B. Hogue – NPCC (2) K. Khan – IESO (2) M. Potishnak – ISONE (2) G. Campoli – NYISO (2)	✓		
New York State Reliability Council (2) Theodore Pappas	✓		
We Energies (3, 4, 5) Howard Rulf	✓		
Calpine (6) James Stanton	✓		

2. Do you agree with the scope and applicability of the proposed standard?

Summary Consideration: Most commenters agreed that the proposed standard should apply to the Reliability Authority (or Reliability Coordinator), Balancing Authority and Generator Operator. With the revisions to the SAR, there are requirements for the Generator Owner to ensure that certain governors meet a minimum set of criteria

There was no consensus amongst commenters on the scope of the proposed standard. The drafting team made extensive changes to try to better define the scope.

Commenter	Yes	No	Comment
MAAC Staff (2) Al DiCaprio – MAAC (2) Joe Willson – MAAC (2) Mark Kuras – MAAC (2)		✓	Frequency Response characteristics should be dictated by the Reliability entities as part of their respective control services to meet the regional synchronizing requirements as well as the longer duration control standards and of the needs of the interconnection in which they operate.
Response: The Resources Subcommittee Frequency Task Force's intent is that the standard be designed such that a BA can mirror the metrics within its boundaries (evaluate generators and LSEs) if it so chooses.			
BPA Bart McManus Brian Tuck James Randall Francis Halpin Bill Mittlestat James Murphy		✓	The main theme that there needs to be a relationship between response and frequency decline is the right approach but requirements would be different from region to region. Standards to manage frequency response should be developed by individual interconnections; not NERC. The scope and applicability should be defined by the needs of the interconnection to provide the most benefit to system wide reliability.
Response: The Resources Subcommittee Frequency Task Force agrees that frequency response is primarily an Interconnection issue and, as envisioned, the Standard would accommodate Interconnection differences both in amounts of response and methodology in calculating response. The drafting team believes that stakeholders would prefer the assurance of knowing that NERC is providing oversight to ensure that all Interconnections have a technically sound basis for the development of respective frequency response requirements.			
NPCC CP9, Reliability Standards Working Group Guy V. Zito – NPCC (2) Ralph Rufrano – NYPA (1) K. Goodman – ISONE (2) Al Adamson – NYSRC (2) Bob Pelligrini – UI (1) D. Kiguel – Hydro One (1) P. Lebro – Nat'l Grid (1) R. Champagne – TE (1) B. Hogue – NPCC (2) K. Khan – IESO (2) M. Potishnak – ISONE (2)		✓	The applicability of this Standard to the LSE should be considered.

Commenter	Yes	No	Comment
G. Campoli – NYISO (2)			
Response: The Resources Subcommittee Frequency Task Force will add LSE to the standard's applicability list.			
MAAC (2) John Horakh		✓	Quoted from the SAR (with corrections): This SAR is proposed to develop a standard to measure sub-minute responses to changes in frequency and to set minimum acceptable responses of the system to these events. Also quoted: The measurement selected must be accurate and, to the extent practical, easy to implement. This seems more like a research project than a request for a standard. There is no mention of any possible measurements that might be in the standard. I'm afraid that proceeding with such a vague idea of a measurement will lead the SAR or later Standard to become bogged down with research and field testing even more so than the Balance Load and Demand Standard. And Balance Load and Demand did have definite measurements in mind, thereby not requiring much research, mainly field testing. Come back with a SAR after the research is done, or at least started.
Response: The Resources Subcommittee Frequency Task Force agrees that the whitepaper bears some resemblance to the description for a research project. Many in the industry are concerned with the decline in Frequency Response, while at the same time some are asking how much of a problem is the decline in response. The drafting team's goal is to put the infrastructure and process in place to make informed decisions in the future and to allow the Regions to evaluate the distribution and adequacy of response and take mitigating action if there are areas found to be deficient. The Resources Subcommittee Frequency Task Force disagrees with delaying the standard development. The SAR will define the scope of the standard. The specific detailed requirements and measures will be developed by the standard drafting team.			
TVA (1) Kathie Davis Larry Akens Mitch Needham Chuck Feagans Ed Forsythe		✓	If the purpose is to purchase frequency response, then the Market Operator needs to be includes. Will this be considered an Ancillary Service? Others that may need to be involved are Transmission Service Provider, Generator Owner, Planning Authority and Resource Planner. Applicability should include #2
Response: The Resources Subcommittee Frequency Task Force agrees that others have roles in providing Frequency Response, but have focused on the higher level calculation of response at the balancing authority and Interconnection level. The primary reason for this is that there are about 150 balancing authorities. Only those balancing authorities with sub-normal response need to investigate to the generator level. The NERC 2002 Generating Unit Statistical Brochure identifies 3694 generators of 1 MW or greater. It would be difficult (and unnecessary if the BA has good response) to monitor thousands of generators with this standard. The standard doesn't preclude market solutions, which NAESB may adopt. The Resources Subcommittee Frequency Task Force agrees with the comment to include #2 in the SAR.			
ISO/RTO Standards Review Committee (2) K. Tammar – NYISO (2) D. McMaster – AESO (2) Ed Riley – CAISO (2) Sam Jones – ERCOT (2)		✓	There is a general need for a standard, but the outcomes and expectations should address the comments raised in question 1. While we agree that the standard should not preclude market solutions (e.g. allow purchasing of response as long as deliverability and restoration criteria can be met), we have concerns with the statement *There must be a means for sale/purchase of frequency response as for any other quantity.*

Commenter	Yes	No	Comment
P. Henderson – IESO (2) P. Brandien – ISO-NE (2) B. Phillips – MISO (2) B. Balmat – PJM (2) C. Yeung – SPP (2) New York ISO (2) Mike Calimano			It is not clear what is meant by *A method of allocation must be developed."* Is this an allocation of Interconnection response to BAs, BA allocation to generators or something different?
Response: The Resources Subcommittee Frequency Task Force agrees with these comments, and has revised the SAR to omit the italicized statements. As envisioned, the proposed standard would not mandate a given amount of frequency response, but would require an analysis if response were measurably below the norm. The standard doesn't preclude market solutions, which NAESB may adopt.			
NCPA (4) Les Pereira		✓	The scope needs to be expanded – see detailed comments in a following section – based on extensive modeling and validation work in WECC.
Response: The Resources Subcommittee Frequency Task Force appreciates the significant work that has been done in this area by the WECC and has referenced some of this research in the Whitepaper. We believe the Planning Standards under development (MOD-13 and MOD-27) deal with the governor issues that you outline. As envisioned, this standard will provide improved data into the modeling process.			
FRCC (2) Linda Campbell Ron Donahey – TEC (1) Mark Bennett – GRU (3) Steve Wallace – SEC (5) S. McElhaney – FMPA (5) Ted Hobson – JEA (1)		✓	The SAR indicates a measure of frequency response for the Interconnection, as a measure of performance. This would be very difficult to translate to individual entity compliance and thus render the standard applicable to no entities.
Response: The interconnection measure of response is intended as a benchmark and as a validation of the balancing authority's reported performance. The revised SAR indicates that if frequency response is outside the norm for the BA, based on its size, BAs and Regions would be required to conduct analyses to determine the reason for the performance.			
IESO (2) Pete Henderson		✓	The Frequency control standard needs to address levels required for reliability, be consistent and verifiable, and be simple to monitor for compliance purposes.
Response: This is the intent.			
Progress Energy – Carolinas (1, 3, 5, 6) Phil Creech	✓		Scope: The scope of the proposed standard is appropriate. However, the reliability requirements would be better addressed by a comprehensive review that considers the adequacy of existing reliability standards. Applicability: The applicability of the proposed standard is understood to be Reliability Authorities, Balancing Authorities, and Generator

Commenter	Yes	No	Comment
			Operators. However, substantial questions remain as to how the responsibilities implied in the proposed standard will be equitably distributed.
Response: The Resources Subcommittee Frequency Task Force appreciates your comment. The new standard for verifying generator governor controls will be under field test through part of 2007 and then will be finalized, balloted and then implemented. The implementation plan for MOD-027 includes additional time for entities to become compliant with the requirements. This would mean that any work on this standard could be delayed for several years. With the decline in Eastern Interconnection frequency response, the drafting team thinks it would be unwise to wait for the new standards to be developed and reviewed before developing this standard. Your questions regarding the applicability of the responsibilities will be better defined during the standard drafting phase of this standard.			
CAISO (2) Ed Riley Yuri Makarov Steve McCoy	✓		Generally, our answer is yes, but the matter of applicability needs a very careful consideration. The question is whether the proposed standard should be applied to only the reliability and balancing authorities and plant operators, or also to the resource and system planning authorities and generator owners. For example, wind generators do not provide a frequency response, whereas the response from the Combined Cycle units is limited. This is a matter of design as well as the matter of controllability of the primary energy source. If the generation portfolio contains a lot of wind and CC generators, the balancing authority cannot do much to improve its summary frequency response in general terms. Also, if frequency responsive generators in a CA are heavily loaded, would the new standard force the balancing authorities to re-dispatch generation in favor of non-responsive generation and commit more responsive generation ahead of the non-responsive generation? Another issue is whether the standard should specify the required response in the area or individual responses from generators. Perhaps, NERC should work with NASB to find the right answers before establishing the standard. One possible solution is to establish penalties for non-compliance that would stimulate generator owners to invest in frequency responsive generation. Another possible recommendation could be establishing a market for frequency response. Without resolving these difficult issues, this standard cannot be accepted.
Response: The Resources Subcommittee Frequency Task Force agrees that there are several issues that must be addressed in the standard or in supporting business practices. As envisioned, the draft standard would not be prescriptive with regard to "how much" and "where" the response is carried. The standard would allow balancing authorities, reliability coordinators, load-serving entities and Regional Reliability Organizations to make informed decisions based on their unique situation.			
Energy Mark, Inc. (8) Howard Illian	✓		Planning standards are not enough by themselves. Without continuous measurement, there can be no assurance that those responsible for meeting the reliability need for Frequency Response are fulfilling those responsibilities. Only a Frequency Response Standard that continuously measures response can insure that the response is available when required.
Response: The Resources Subcommittee Frequency Task Force agrees with your comment. The SAR drafting team will follow the Planning Standards under development (MOD-13 and MOD-27) that deal with governors and frequency response to be sure there are no conflicts.			

Commenter	Yes	No	Comment
TXU Energy Delivery Roy Boyer	✓		Yes, I agree.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
MISO Terry Bilke	✓		I agree, with some qualification. While the standard shouldn't preclude market solutions, I don't think it must enable a market as the scope implies. A little more clarity on the goals of the standard is needed.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments and has removed the reference in the original SAR to market solutions.			
Dick Schulz Chair, IEEE Task Force on Large Interconnected Power System Response to Generation Governing	✓		The proposed scope and applicability, to the extent that they are in the given in the SAR, are good.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
We Energies (3, 4, 5) Howard Rulf	✓		
Manitoba Hydro (1, 3, 5, 6) Gerald Rheault	✓		
Calpine (6) James Stanton	✓		
Alliant Energy (1) Kenneth A. Goldsmith	✓		
MRO (2) Larry Larson – OTTP Al Boesch – NPPD Terry Bilke – MISO R. Coish – MH Dennis Florom – LES K. Goldsmith – Alliant Todd Gosnell – OPPD W. Guttormson – SaskPwr Jim Maenner – WPS Tom Mielnik – MidAmerican Darrick Moe – WAPA Joe Knight – MRO	✓		
Southern Company Transmission, Operations, Planning and	✓		

Commenter	Yes	No	Comment
EMS Divisions (1) Marc Butts Steve Corbin Jim Viikinsalo Jim Griffith Doug McLaughlin Monroe Landrum			
NERC Frequency Task Force Raymond L. Vice, Chairman	✓		
Robert Blohm	✓		
SPP Operating Reliability Working Group Robert Rhodes –SPP (2) Ron Ciesiel – SPP (2) Bob Cochran – SPS (1) Mike Gammon – KCPL (1) Steve Hillman – WPEK (1) Allen Klassen – Westar (1) Bill Nolte – SECI (1) Mike Stafford – GRDA (1)	✓		
Southern Co. Generation (6) Roman Carter Tony Reed Joel Dison Lucius Burris Lloyd Barnes Clifford Shepard Terry Crawley Roger Green Tom Higgins	✓		
New York State Reliability Council (2) Theodore Pappas	✓		
TXU Electric Delivery (1) Travis Besier or Ellis Rankin	✓		

3. Do you believe these standards are more appropriately additions to existing standards as opposed to creating new standards?

Summary Consideration: There was no consensus amongst commenters on this issue. Refinement of this SAR was delayed for a year. During that time other related standards have undergone considerable development, and are on a schedule that would not be improved by the addition of the requirements envisioned with the Frequency Response standard. For these reasons, the drafting team is recommending that the new requirements for Frequency Response be in a new, stand-alone standard.

Commenter	Yes	No	Comment
BPA Bart McManus Brian Tuck James Randall Francis Halpin Bill Mittlestat James Murphy		✓	WECC has been working on frequency response standards for a few years and is close to finalizing standards specifically for the WECC interconnection. We do think there is a need for standardization of frequency response (clearly we do since WECC is doing it) BUT this standard should be developed at the Regional Council or Interconnection level and then adopted by NERC as a "Standard" with regional differences. Any new standards concerning frequency response should be developed by the individual interconnections.
Response: The Resources Subcommittee Frequency Task Force agrees that frequency response is primarily an Interconnection issue and the proposed standard accommodates Interconnection differences both in amounts of response and methodology in calculating response. The SAR's detailed description has been expanded to include broader parameters, including frequency response calculations that are Interconnection-specific. The drafting team believes that stakeholders would prefer the assurance of knowing that NERC is providing oversight to ensure that all Interconnections have a technically sound basis for the development of respective frequency response requirements.			
CAISO (2) Ed Riley Yuri Makarov Steve McCoy		✓	The new standard should a stand-alone standard because of its potential implications for control areas and the necessity to stage the implementation of the standard in coordination with resolution of the issues discussed above.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
Robert Blohm		✓	The SAR acknowledges that the proposed Standard not only is complementary to the Balancing Resources and Demand Standard, but also must be coordinated with that Standard. The two standards could be combined. But that is insufficient reason to oppose development of a separate Frequency Response Standard. Moreover, combining the standards would reverse the great progress made in consensus on the Balancing Resources and Demand Standard.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
MAAC (2) John Horakh		✓	Adding this requirement to another standard would only slow down the progress of both.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
ISO/RTO Standards Review		✓	Unless the Version 0 (BAL-003-0 — Frequency

Commenter	Yes	No	Comment
Committee (2) K. Tammar – NYISO (2) D. McMaster – AESO (2) Ed Riley – CAISO (2) Sam Jones – ERCOT (2) P. Henderson – IESO (2) P. Brandien – ISO-NE (2) B. Phillips – MISO (2) B. Balmat – PJM (2) C. Yeung – SPP (2)			Response and Bias) can be clarified and brought in line with this proposed standard, it should be stand-alone.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
NCPA (4) Les Pereira		✓	A new SAR will be more prescriptive, however there is also need for other related sections in NERC Operating Policy and Planning that need to be modified – see other comments below.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
IESO (2) Pete Henderson		✓	If the existing Frequency Response and Bias Standard Version 0 (Bal-003-0) can not be clarified and brought in line with this proposed standard, it should be standalone.
Response: The Resources Subcommittee Frequency Task Force agrees with this comment.			
MAAC Staff (2) Al DiCaprio – MAAC (2) Joe Willson – MAAC (2) Mark Kuras – MAAC (2)		✓	
Manitoba Hydro (1, 3, 5, 6) Gerald Rheault		✓	
We Energies (3, 4, 5) Howard Rulf		✓	
Calpine (6) James Stanton		✓	
TVA (1) Kathie Davis Larry Akens Mitch Needham Chuck Feagans Ed Forsythe		✓	
FRCC (2) Linda Campbell Ron Donahey – TEC (1) Mark Bennett – GRU (3)		✓	

Commenter	Yes	No	Comment
Steve Wallace – SEC (5) S. McElhaney – FMPA (5) Ted Hobson – JEA (1)			
New York ISO (2) Mike Calimano		✓	
New York State Reliability Council (2) Theodore Pappas		✓	
TXU Electric Delivery (1) Travis Besier or Ellis Rankin		✓	
NPCC CP9, Reliability Standards Working Group Guy V. Zito – NPCC (2) Ralph Rufrano – NYPA (1) K. Goodman – ISONE (2) Al Adamson – NYSRC (2) Bob Pelligrini – UI (1) D. Kiguel – Hydro One (1) P. Lebro – Nat'l Grid (1) R. Champagne – TE (1) B. Hogue – NPCC (2) K. Khan – IESO (2) M. Potishnak – ISONE (2) G. Campoli – NYISO (2)		✓	
Progress Energy – Carolinas (1, 3, 5, 6) Phil Creech	✓		The reliability requirements provided in the proposed standard would be better addressed by a comprehensive review that considers the adequacy of the existing reliability standards (i.e., 300 - Balance Resources and Demand)
Response: Frequency Response was consciously left out of the Balance Resources and Demand (BR&D) standard. We agree that the Frequency Response standard should complement the BR&D standard and believe it does.			
Energy Mark, Inc. (8) Howard Illian	✓		Frequency Response is closely related to the Frequency Bias used in the Balancing Resources and Demand Standard and therefore this standard should be included as an addition to that standard. If it is not included in the BRD Standard, a separate standard would require coordination between the two standards. This would make the process of updating the standards more complex.
Response: The Resources Subcommittee Frequency Task Force acknowledges that if the frequency response requirements and measures were to be included in another standard that the Balance Resources and Demand standards would be the most likely standard(s). The Resources Subcommittee Frequency Task Force is working with the Balance Resources and Demand standard drafting team to ensure that the efforts of both teams are coordinated.			

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Alliant Energy (1)
Kenneth A. Goldsmith</td><td>✓</td><td></td><td>Version 0 of BAL-003-0, Frequency Response and Bias; or its successor.</td></tr>
<tr><td colspan="4">Response: The Balance Resources and Demand standard drafting team has a successor version of Frequency Bias posted for review. The Resources Subcommittee Frequency Task Force is working with the Balance Resources and Demand standard drafting team to ensure that the efforts of both teams are coordinated.</td></tr>
<tr><td>MRO (2)
Larry Larson – OTTP
Al Boesch – NPPD
Terry Bilke – MISO
R. Coish – MH
Dennis Florom – LES
K. Goldsmith – Alliant
Todd Gosnell – OPPD
W. Guttormson – SaskPwr
Jim Maenner – WPS
Tom Mielnik – MidAmerican
Darrick Moe – WAPA
Joe Knight – MRO</td><td>✓</td><td></td><td>Version 0 (BAL-003-0 — Frequency Response and Bias) or its successor is a logical place. Depending on the outcome of the V1 Balance Resource and Demand standard, it could reside there.</td></tr>
<tr><td colspan="4">Response: : The Balance Resources and Demand standard drafting team has a successor version of Frequency Bias posted for review. The Resources Subcommittee Frequency Task Force is working with the Balance Resources and Demand standard drafting team to ensure that the efforts of both teams are coordinated.</td></tr>
<tr><td>Southern Company Transmission, Operations, Planning and EMS Divisions (1)
Marc Butts
Steve Corbin
Jim Viikinsalo
Jim Griffith
Doug McLaughlin
Monroe Landrum</td><td>✓</td><td></td><td>The Frequency Response Standard could be included as part of the Balance Resources and Demand Standard.

Comments
Since both the Frequency Response Standard and the Balance Resources and Demand Standard address frequency, they obviously must work together closely. If they are crafted, as originally intended by the Frequency Taskforce, to utilize the same CPS database, there may be savings in administrative overhead in putting them both in the same standard.</td></tr>
<tr><td colspan="4">Response: The intent is for the Frequency Response Standard to complement the Balance Resources and Demand standards. The Resources Subcommittee Frequency Task Force is working with the Balance Resources and Demand standard drafting team to ensure that the efforts of both teams are coordinated. The ‘new’ Balance Resources and Demand standards are close to completion and cover related but different topics from those in the proposed Frequency Response SAR. There doesn’t seem to be any benefit in stalling the implementation of the new Balance Resources and Demand standards while the technical details of the new Frequency Response standard are developed, tested and then implemented.</td></tr>
<tr><td>ATC (1)
Peter Burke</td><td>✓</td><td></td><td>II.B.S1M5, Test results of speed/load governor controls.</td></tr>
</table>

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>Comments
It may be appropriate to include this standard in the Phase III/IV standards that address speed/load governor controls (II.B.S1M5, Test results of speed/load governor controls). The three following customer demand related standards would be helpful in defining load response to frequency excursions:

II.E.S1.M1, Plans for the evaluation and reporting of voltage & Frequency characteristics of customer demands.

IIE.S1.M2 Documentation or requirements for determining dynamic characteristics of customer demands.

II.E.S1.M3, Customer (dynamic) demand data.</td></tr>
<tr><td colspan="4">Response: The drafting team will follow the development of the Phase III/IV planning standards under development (MOD-13 and MOD-27) that deal with governors and frequency response to be sure there are no conflicts. The Resources Subcommittee Frequency Task Force believes that a Frequency Response standard could simplify what is proposed in the planning standards if it allowed an on-line calculation of generator response.</td></tr>
<tr><td>NERC Frequency Task Force
Raymond L. Vice, Chairman</td><td>✓</td><td></td><td>The Frequency Response Standard could be included as part of the Balance Resources and Demand Standard.

Comments
Since both the Frequency Response Standard and the Balance Resources and Demand Standard address frequency, they obviously must work together closely. If they are crafted, as originally intended by the Frequency Taskforce, to utilize the same CPS database, there may be savings in administrative overhead in putting them both in the same standard.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force's intent is for the Frequency Response Standard to complement the Balance Resources and Demand standards. The 'new' Balance Resources and Demand standards are close to completion and cover related but different topics from those in the proposed Frequency Response SAR. There doesn't seem to be any benefit in stalling the implementation of the new Balance Resources and Demand standards while the technical details of the new Frequency Response standard are developed, tested and then implemented.</td></tr>
<tr><td>SPP Operating Reliability Working Group
Robert Rhodes –SPP (2)
Ron Ciesiel – SPP (2)
Bob Cochran – SPS (1)
Mike Gammon – KCPL (1)
Steve Hillman – WPEK (1)
Allen Klassen – Westar (1)</td><td>✓</td><td></td><td>We would recommend that this standard be incorporated into the Balance Resource and Demand Standard (Standard 300) or the Version 0 BAL Standard.</td></tr>
</table>

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Bill Nolte – SECI (1)
Mike Stafford – GRDA (1)</td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force’s intent is for the Frequency Response Standard to complement the Balance Resources and Demand standards. The ‘new’ Balance Resources and Demand standards are close to completion and cover related but different topics from those in the proposed Frequency Response SAR. There doesn’t seem to be any benefit in stalling the implementation of the new Balance Resources and Demand standards while the technical details of the new Frequency Response standard are developed, tested and then implemented.</td></tr>
<tr><td>Southern Co. Generation (6)
Roman Carter
Tony Reed
Joel Dison
Lucius Burris
Lloyd Barnes
Clifford Shepard
Terry Crawley
Roger Green
Tom Higgins</td><td>✓</td><td></td><td>The Frequency Response Standard could be included as part of the Balance Resources and Demand Standard.

Comments
Since both the Frequency Response Standard and the Balance Resources and Demand Standard address frequency, they obviously must work together closely. If they are crafted, as originally intended by the Frequency Taskforce, to utilize the same CPS database, there may be savings in administrative overhead in putting them both in the same standard.</td></tr>
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<tr><td>MISO
Terry Bilke</td><td>✓</td><td></td><td>It’s not a major issue. It appears it should be include in the Version 0 (BAL-003-0 — Frequency Response and Bias).</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force’s intent is for the Frequency Response Standard to complement the Balance Resources and Demand standards. The ‘new’ Balance Resources and Demand standards are close to completion and cover related but different topics from those in the proposed Frequency Response SAR. There doesn’t seem to be any benefit in stalling the implementation of the new Balance Resources and Demand standards while the technical details of the new Frequency Response standard are developed, tested and then implemented.</td></tr>
<tr><td>Dick Schulz
Chair, IEEE Task Force on Large Interconnected Power System Response to Generation Governing</td><td></td><td></td><td>No comment.</td></tr>
<tr><td>TXU Energy Delivery
Roy Boyer</td><td></td><td></td><td>No opinion.</td></tr>
</table>

4. Do you have any additional comments regarding the SAR that you believe should be addressed?

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>MAAC Staff (2)
Al DiCaprio – MAAC (2)
Joe Willson – MAAC (2)
Mark Kuras – MAAC (2)</td><td>✓</td><td></td><td>The SAR requestor has not provided any indication of a reliability problem. Decreasing frequency response is in and of itself not a reliability problem - more evidence is required as to the magnitude of the threat.

Any standard that is proposed, regarding frequency response, should consider both generator and load response. If Load response does provide a significant portion of the frequency response (as some people contend) then that resource must be considered in the proposal. In short the standard must make clear whether it is for interconnection response or for balancing area response or for individual generator response and individual load response.</td></tr>
<tr><td colspan="4">Response: Most commenters indicated that they feel that there is a reliability-related need for a standard to address Frequency Response.
The standard is not intended to establish a large set of arbitrary requirements, but will establish the framework to collect the information to make informed engineering decisions. Additional detail has been added to the SAR's Purpose/Industry Need and the Detailed Description. The revised SAR does not specifically consider load response but does state that the proposed standard will include requirements for the Interconnection response, for the installation of governors and for BAs to operate their automatic generation control function on tie-line frequency bias and for BAs to respond to requests for information on frequency response. The revised SAR does not include requirements for generators to provide response and does not address load response.</td></tr>
<tr><td>BPA
Bart McManus
Brian Tuck
James Randall
Francis Halpin
Bill Mittlestat
James Murphy</td><td>✓</td><td></td><td>Frequency response requirements are likely different for each of the three interconnected regions and a generalized approach will likely not meet WECC needs. The danger here is that a NERC-wide approach may not be compatible with the needs of a regional approach. Standards are currently being developed within WECC to address the frequency response concerns of this interconnection. We feel that if the Eastern Interconnection needs a Frequency Response Standard, they should utilize the NERC Frequency Response Standard Whitepaper to draft an Eastern Interconnection-specific Frequency Response Standard.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees that frequency response is primarily an Interconnection issue and the proposed standard accommodates Interconnection differences both in amounts of response and methodology in calculating response. As noted in and earlier response, we would expect some general technical and engineering principles that should be met in order to calculate and evaluate the amount and distribution of frequency response. Additional SAR Detailed Description details have been added.
The drafting team believes that stakeholders would prefer the assurance of knowing that NERC is providing oversight to ensure that all Interconnections have a technically sound basis for the development of respective frequency response requirements.</td></tr>
<tr><td>Manitoba Hydro (1, 3, 5, 6)
Gerald Rheault</td><td>✓</td><td></td><td>Below are a few general comments on the SAR:
There is general agreement with the statement "reliance on load as the sole support to arrest the frequency can lead to a decline in the reliability of the grid" in paragraph 3, page 4 of the white paper. However enough information is not provided to</td></tr>
</table>

Commenter	Yes	No	Comment
			substantiate statements earlier in the paragraph such as, “the turn around in frequency from points C to B attributable to unit governor response has markedly declined and at times is non-existent in the eastern interconnection” and “the line from points C to D is shifting down and becoming horizontal”. In areas where governor response is limited it may be necessary to explore the necessity of earmarking “high-set” blocks of load , as is practiced in ERCOT, to act as a supplementary to governor response. Although it is anticipated that this approach would probably be much more difficult and challenging to co-ordinate in larger areas. There should be careful thought put into the system/interconnection performance targets for frequency response. Perhaps the bar should be higher than preventing UFLS for credible generation loss events, i.e., provide a margin above this level. At the same time the standard should not impose unreasonable costs on entities to demonstrate compliance. The performance target should address both total interconnection response and also area or system response (potential islanding) and be very clear how generator operators (or load) obligations are allocated to achieve the performance targets. NERC should investigate a process to monitor interconnection frequency response to be able to measure performance.
Response: As envisioned, the standard will accommodate special needs of each Interconnection. It will not preclude load from being part of the solution. While not part of the standard, the Resources Subcommittee is pursuing the addition of functionality in the “NERC ACE-Frequency monitoring application” that will identify generator trips and automate the calculation of Interconnection frequency response. Evidence to date indicates that frequency response declines significantly during light load periods, even though the exact mechanism for this is not well defined. Most of the major frequency excursions experienced in the Eastern Interconnection have occurred during the shoulder period of the year during either the early morning or late evening periods.			
NPCC CP9, Reliability Standards Working Group Guy V. Zito – NPCC (2) Ralph Rufrano – NYPA (1) K. Goodman – ISONE (2) Al Adamson – NYSRC (2) Bob Pelligrini – UI (1) D. Kiguel – Hydro One (1) P. Lebro – Nat’l Grid (1) R. Champagne – TE (1) B. Hogue – NPCC (2) K. Khan – IESO (2) M. Potishnak – ISONE	✓		CHANGE This SAR is proposed to develop a standard to measure sub-minute responses to changes in frequency and to set minimum acceptable responses to system these events. TO This SAR is proposed to develop a standard to measure sub-minute responses to changes in frequency and to set minimum acceptable responses to these system events.

Commenter	Yes	No	Comment
(2) G. Campoli – NYISO (2)			
Response: The SAR has been revised and no longer includes this phrase.			
Energy Mark, Inc. (8) Howard Illian	✓		NERC has the responsibility of maintaining reliability on the North American Interconnections. NERC cannot perform that function effectively if it waits for reliability problems to become apparent in system operations before it takes actions to address those problems. NERC must be a forward looking organization that anticipates future reliability problems and takes actions to resolve those problems before they affect interconnection reliability.
Response: The Resources Subcommittee Frequency Task Force agrees with the comments and has made substantial changes to the SAR's Purpose/Industry Needs and the Detailed Description reflecting the industry comments.			
Calpine (6) James Stanton	✓		Given the language in the accompanying White Paper: The standard should not preclude market solutions (e.g. allow purchasing of response as long as deliverability and restoration criteria can be met).There must be a means for sale/purchase of frequency response as for any other quantity. – I believe this Standard should be developed in conjunction with NAESB. The definition, attributes and procurement metrics of the frequency response product will be a critical component of this Standard. Some guidance in defining and developing this service to the bulk interconnected system can be found in the NERC IOS Reference Document. The Standard should build on this previous IOS work.
Response: The Resources Subcommittee Frequency Task Force intent for this proposed standard does not preclude market solutions. Language in the original SAR that referenced markets has been removed and is not in the revised SAR. We hope that the previous IOS work and the related MOD standards will provide balancing authorities a means to obtain frequency response where needed. It is quite possible that NAESB will pick up where the IOS left off.			
MAAC (2) John Horakh	✓		It appears Frequency Response is an accepted term used for this requirement, and therefore might be difficult to change. However, Frequency Response is not a very good description of the requirement. A term such as Transient Generator and Load Response would be more descriptive.
Response: Transient Generator and Load Response probably is a more descriptive than Frequency Response. Note that the focus of the proposed standard would be on generator response, not on load response. . The Resources Subcommittee Frequency Task Force agrees that changing the name from Frequency Response would likely encounter resistance.			
ISO/RTO Standards Review Committee (2) K. Tammar – NYISO (2) D. McMaster – AESO (2) Ed Riley – CAISO (2) Sam Jones – ERCOT (2) P. Henderson – IESO (2)	✓		We appreciate the opportunity to comment and believe there is a need for such a standard. It needs to be recognized that there are two objectives for governor response, namely, to provide response on an interconnection wide basis to maintain an acceptable frequency and secondly to control frequency in island situations. The former may allow for averaging over an area of the response

Commenter	Yes	No	Comment
P. Brandien – ISO-NE (2) B. Phillips – MISO (2) B. Balmat – PJM (2) C. Yeung – SPP (2)			requirement but the latter may limit the extent of averaging. Published studies show frequency response is declining when it should be increasing with load. The main concerns with this decreasing performance are: There may be areas unable to withstand severe disturbances. Following a grid separation or collapse, control areas may be unable to fulfill their blackstart and restoration responsibilities, thereby becoming a burden to neighbors. Because engineering models use theoretical frequency response, they are likely over optimistic and may misstate grid stability limits. This standard would allow the industry to determine whether the decline is local or global. Rather than implementing a complicated infrastructure or process, we would suggest that NERC automate the calculation of frequency response by either: Asking BAs to save their CPS-source data in a common format so a common tool can be used (MAPP BAs and some others use a common tool that can calculate frequency response with CPS-source data). Embed the calculation in the NERC ACE-monitoring application. Refer to our earlier comments the structure of the standard (where lower amounts of BA response trigger an internal assessment rather than automatic assignment of non-compliance). BAs (and ultimately generators) would only be initially non-compliant if their response was low AND the BA failed to perform a reliability assessment in conjunction with its TOP. Non compliance should be assessed if the BA does not alleviate the deficiency within a reasonable timeframe. This default assessment would be at the BA level, but could be on an area basis (likely islanding area or where a TSP has responsibility for frequency responsive and black start ancillary services). The standard should employ a methodology that not only captures initial response (first few seconds after the event) but also the sustained response until AGC action takes over Each Interconnection should have the ability to add and further define the standard to meet its needs.

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>Providing visibility on where and when performance is substandard will likely initiate sufficient action to arrest the decline in performance. Minimum performance standards could be implemented <u>after</u> the industry has identified what is reasonably achievable and technically justified.</td></tr>
<tr><td colspan="4">Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. A envisioned, the standard will measure response for perhaps a minute to ensure response is not withdrawn immediately after it is provided.

The proposed standard would not mandate a given amount of response, but would requires an analysis if response were measurably below the norm. The proposed standard would accommodate the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee has a tool that could calculate the BA's performance to the standard.

The drafting team agrees that performance requirements must be validated by the industry. As you suggested, a long field test may be needed before justifiable minimum performance standards can be identified.</td></tr>
<tr><td>MRO (2)
Larry Larson – OTTP
Al Boesch – NPPD
Terry Bilke – MISO
R. Coish – MH
Dennis Florom – LES
K. Goldsmith – Alliant
Todd Gosnell – OPPD
W. Guttormson – SaskPwr
Jim Maenner – WPS
Tom Mielnik – MidAmerican
Darrick Moe – WAPA
Joe Knight – MRO</td><td>✓</td><td></td><td>We appreciate the opportunity to comment and believe there is a need for such a standard. Published studies show frequency response is declining when it should be increasing with load.

Because there is no process in place to track BA or Interconnection response, we don't know whether the decline is local or global. Primary concerns with this decreasing performance in primary control:
1. There may be areas unable to withstand severe disturbances.
2. Following a grid separation or collapse, control areas may be unable to fulfill their blackstart and restoration responsibilities, thereby becoming a burden to neighbors.
3. Because engineering models use theoretical frequency response, they are likely overoptimistic and may misstate grid stability limits.

Rather than putting in a complicated infrastructure or process, we would suggest that NERC automate the calculation of frequency response by either:
• Asking BAs to save their CPS-source data in a common format so a common tool can be used (MAPP BAs and some others use a common tool that can calculate frequency response with CPS-source data).
• Embed the calculation in the NERC ACE-monitoring application.

The standard will need to acknowledge the large variability in individual responses at each BA due to coincident load changes and amount and mix of generation. In addition, smaller Interconnections likely need greater response.

Refer to our earlier comments the structure of the standard</td></tr>
</table>

Commenter	Yes	No	Comment
			(where lower amounts of response trigger an internal assessment rather than assessment non-compliance). BAs (and ultimately generators) would only be initially non-compliant if their response was low AND they failed to perform the reliability assessment. Providing visibility on where and when performance is substandard will likely initiate sufficient action to arrest the decline in performance. Minimum performance standards could be implemented after the industry has identified what is reasonably achievable and technically justified. The standard should not preclude market solutions to providing frequency response, but such arrangements would need to be looked at closely to be sure they fulfill reliability needs.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. As envisioned, the proposed standard would not mandate a given amount of response, but would require an analysis if response were measurably below the norm. The proposed standard would accommodate the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee has a tool that could calculate the BA's performance to the standard. The Resources Subcommittee Frequency Task Force acknowledges the variability inherent in measuring frequency response. The standard will require capturing sufficient samples to make an objective measurement. The proposed standard does not preclude market solutions. The new requirements may need to be field tested for a long duration before compliance with the requirements is mandatory. As envisioned, the standard does not mandate a specific amount of response, but requires analysis if response is markedly below the norm. Analysis may identify the need for corrective measures and the standard will accommodate the necessary time to make corrections. The references to market solutions that were contained in the original SAR have been removed. NAESB may choose to develop associated business practices.			
NCPA (4) Les Pereira	✓		Two statements are made in the SAR: 1. The purpose of the proposed SAR is to ensure that frequency of the Interconnection remains above underfrequency load shedding setpoints during the transient period following the sudden loss of generation on the Interconnection. 2. Furthermore, it is stated that " In regard to frequency response, one shortcoming of the recommendations in policy today is that there is no guidance regarding how much governor response (in MW) is required at the 5% droop rate." The first is a calculated number and depends not only on the amount of generation tripped, but also the total generation in the Whole Interconnection at the time of trip. Obviously two very different answers will be obtained : one with the Interconnection intact (normal operation) and the second when islanded. Both affect reliability. The second issue has been thoroughly investigated in the WECC and a new Thermal Governor modeling approach has

Commenter	Yes	No	Comment
			been implemented in the WECC after system tests, an exhaustive modeling validation effort and obtaining data from the generator owners. This has been documented in two IEEE Transaction papers described below. These papers present the development of a new turbine-governor modeling approach in WECC that correctly represents thermal units that have demonstrated unresponsive characteristics such as "base loaded" units operated with limiters, or partially responsive units with MW-load-controllers. The May 18th 2001 system trip test for 1250 MW performed with all AGCs off indicated that only about 40% of the governors effectively responded in the real system. If all the governors were responsive the calculated generation pickup for governors with a 5% droop for a 0.1 Hz frequency deviation would be 3185 MW instead of 1250 MW. The new modeling approach has been extensively validated against recordings from three WECC system tests and several large disturbances, and has been approved for use in all operation and planning studies in the WECC. The second paper describes the steps being taken to obtain validated data for the new governor models. The work done by WECC indicate clearly that we do not get the required 5% droop from all units as required by NERC. The modeling approach taken was to model the governors in planning and operating studies exactly as they are being actually operated. Enforcement/compliance of the 5% droop is a separate issue and must be addressed by operating policies. Obviously, the SAR touches upon only part of the problem, but it is a good start and should be expanded. It also needs to be cross-referenced with other areas such as the 5% droop requirement, an effective spinning reserves policy that actually works (see the papers), and the effect on 'governor' powerflow and voltage stability analysis as a result of "unresponsive" governors. The white paper referred by the SAR only touches upon the WECC effort and seems to miss the whole point of the modeling and validation work by the Governor Modeling Task Force in WECC - and what we have achieved in WECC to address realistic modeling of unresponsive governors in the real system. 1. "A New Thermal Governor Modeling Approach in the WECC" by L. Pereira, J. Undrill, D. Kosterev, D. Davies, S. Patterson, *IEEE Trans. Power Systems*, vol. 18, Issue.2, pp. 819-829, May 2003. (*IEEE 2004 prize paper). Presented at Toronto IEEE PES, July 2003.* 2. "New Thermal Governor Model Selection and Validation in the WECC" by Les Pereira, Dmitry

Commenter	Yes	No	Comment
			Kosterev, Donald Davies, and Shawn Patterson - IEEE TPWRS – Vol.19, No.1, pp 517-523, February 2004. *Presented at Denver IEEE PES, July 2004.*
Response: The Resources Subcommittee Frequency Task Force appreciates the significant work that has been done in this area by the WECC and has referenced some of this research in the Whitepaper. We believe the Planning Standards under development (MOD-13 and MOD-27) deal with the detailed governor issues that you have outlined. The Resources Subcommittee Frequency Task Force appreciates the importance of the modeling effort you mention. This standard is not intended to address the modeling issues, but provides the framework and data needed to support the modeling. The SAR was modified to include basic governor requirements.			
FRCC (2) Linda Campbell Ron Donahey – TEC (1) Mark Bennett – GRU (3) Steve Wallace – SEC (5) S. McElhaney – FMPA (5) Ted Hobson – JEA (1)	✓		At this time the FRCC has the highest frequency settings for load shedding in the Eastern Interconnection (southern part of the Region). Being a peninsula and out of necessity, the Region has developed a well coordinated, under-frequency program for extreme frequency excursions. Ambiguity of the requirements, uncertainty of measurement and the lack of benefit to the Region require that the FRCC to oppose this Standard Authorization Request at this time.
Response: The interconnection measure of response is intended as a benchmark and as a validation of BAs' reported performance.			
Southern Company Transmission, Operations, Planning and EMS Divisions (1) Marc Butts Steve Corbin Jim Viikinsalo Jim Griffith Doug McLaughlin Monroe Landrum	✓		We believe that the industry will be exposing the interconnected electrical systems of North America to a significant degree of reliability risk if a Frequency Response Standard similar to the one proposed by this SAR is not adopted. This risk can be mitigated somewhat by the turbine governor requirements of Standard MOD-014-1 from the Phase III/IV Standards SAR, if passed. However, the risk can be managed properly (and in the most economical manner) only on an interconnection/balancing authority basis, not on an individual generator basis as required by Standard MOD-014-1. *What is important is that the interconnections maintain sufficient frequency responsive resources to ensure the stability of interconnection frequency under first contingency conditions. The Frequency Response Standard, as proposed, sets requirements for the management and deployment of frequency responsive resources that achieve this goal without unduly interfering with the on going operation of the interconnection. We strongly urge the industry to support this SAR.*
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
New York ISO (2) Mike Calimano	✓		We appreciate the opportunity to comment and believe there is a need for such a standard. Published studies show frequency response is declining when it should be increasing with load. The main concerns with this decreasing performance are:

Commenter	Yes	No	Comment
			There may be areas unable to withstand severe disturbances. Following a grid separation or collapse, control areas may be unable to fulfill their blackstart and restoration responsibilities, thereby becoming a burden to neighbors. Because engineering models use theoretical frequency response, they are likely overoptimistic and may misstate grid stability limits. This standard would allow the industry to determine whether the decline is local or global. Rather than implementing a complicated infrastructure or process, we would suggest that NERC automate the calculation of frequency response by either: Asking BAs to save their CPS-source data in a common format so a common tool can be used (MAPP BAs and some others use a common tool that can calculate frequency response with CPS-source data). Embed the calculation in the NERC ACE-monitoring application. Refer to our earlier comments the structure of the standard (where lower amounts of BA response trigger an internal assessment rather than automatic assignment of non-compliance). BAs (and ultimately generators) would only be initially non-compliant if their response was low AND the BA failed to perform a reliability assessment in conjunction with its TOP. This default assessment would be at the BA level, but could be on an area basis (likely islanding area or where a TSP has responsibility for frequency responsive and black start ancillary services). The standard should employ a methodology that not only captures initial response (first few seconds after the event) but also the sustained response until AGC action takes over Each Interconnection should have the ability to add and further define the standard to meet its needs. Providing visibility on where and when performance is substandard will likely initiate sufficient action to arrest the decline in performance. Minimum performance standards could be implemented <u>after</u> the industry has identified what is reasonably achievable and technically justified.

Commenter	Yes	No	Comment
			CHANGE This SAR is proposed to develop a standard to measure sub-minute responses to changes in frequency and to set minimum acceptable responses to system these events. TO This SAR is proposed to develop a standard to measure sub-minute responses to changes in frequency and to set minimum acceptable responses to these system events.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments as a whole. The proposed standard does not mandate a given amount of response, but requires an analysis if response is measurably below the norm. The proposed standard accommodates the simplification ideas you propose, and in fact, if data is saved in a common format, the Resources Subcommittee has a tool that will calculate the BA's performance to the standard. The Resources Subcommittee Frequency Task Force has added to the Detailed Description requirements that all balancing authorities shall operate their AGC function on tie-line frequency bias and that all balancing authorities shall perform frequency response characteristics surveys when called for by NERC. The Resources Subcommittee Frequency Task Force agrees with the sub-minute responses comment and has made the change. The new requirements may need to be field tested for a long duration before compliance with the requirements is mandatory. A long field test with extensive data collection may be needed before justifiable minimum performance standards can be identified. The references to market solutions that were contained in the original SAR have been removed. NAESB may choose to develop associated business practices. As envisioned, the standard will measure the response for up to 60 seconds to ensure initial response is not withdrawn. The standard will also provide interconnection flexibility. The phrase noted (starting with , 'This SAR. . . ') was removed from the revised SAR.			
IESO (2) Pete Henderson	✓		We appreciate the opportunity to comment and believe there is a need for such a standard. It needs to be recognized that there are two objectives for governor response, namely, to provide response on an interconnection wide basis to maintain an acceptable frequency and secondly to control frequency in island situations. The former may allow for averaging over an area of the response requirement but the latter may limit the extent of averaging. Published studies show frequency response is declining when it should be increasing with load. The main concerns with this decreasing performance are: There may be areas unable to withstand severe disturbances. Following a grid separation or collapse, control areas may be unable to fulfill their blackstart and restoration responsibilities, thereby becoming a burden to neighbors. Because engineering models use theoretical frequency response, they are likely over optimistic and may misstate grid stability limits.

Commenter	Yes	No	Comment
			This standard would allow the industry to determine whether the decline is local or global. Rather than implementing a complicated infrastructure or process, we would suggest that NERC automate the calculation of frequency response by either: Asking BAs to save their CPS-source data in a common format so a common tool can be used (MAPP BAs and some others use a common tool that can calculate frequency response with CPS-source data). Embed the calculation in the NERC ACE-monitoring application. The standard should employ a methodology that not only captures initial response (first few seconds after the event) but also the sustained response until AGC action takes over Providing visibility on where and when performance is substandard will likely initiate sufficient action to arrest the decline in performance. Minimum performance standards could be implemented after the industry has identified what is reasonably achievable and technically justified.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments. We agree that smaller areas need greater response, and this concept will be applied in establishing the initial target responses for the interconnections (the historic response will bear this out). Under the ERO, interconnections can also establish stricter targets. The new requirements may need to be field tested for a long duration before compliance with the requirements is mandatory. A long field test with extensive data collection may be needed before justifiable minimum performance standards can be identified. As envisioned, the standard will measure the response for up to 60 seconds to ensure initial response is not withdrawn. The references to market solutions that were contained in the original SAR have been removed. NAESB may choose to develop associated business practices.			
NERC Frequency Task Force Raymond L. Vice, Chairman	✓		I personally believe that the industry will be exposing the interconnected electrical systems of North America to a significant degree of reliability risk if a Frequency Response Standard similar to the one proposed by this SAR is not adopted. This risk can be mitigated somewhat by the turbine governor requirements of Standard MOD-014-1 from the Phase III/IV Standards SAR, if passed. However, the risk can be managed properly (and in the most economical manner) only on an interconnection/balancing authority basis, not on an individual generator basis as required by Standard MOD-014-1. What is important is that the interconnections maintain sufficient frequency responsive resources to ensure the stability of

Commenter	Yes	No	Comment
			interconnection frequency under first contingency conditions. The Frequency Response Standard, as proposed, sets requirements for the management and deployment of frequency responsive resources that achieve this goal without unduly interfering with the on going operation of the interconnection. I strongly urge the industry to support this SAR.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
Dick Schulz Chair, IEEE Task Force on Large Interconnected Power System Response to Generation Governing			First, I make these comments based on work that I've done principally at American Electric Power Service Corp, before my retirement from there in November 2000, and as founding Chair of the IEEE Task Force on Large Interconnected Power System Response to Generation Governing. These comments are entirely mine, and reflect no views of either body. Second. It appears that the final standard will differ from any single person's opinions. Thus the specific comments below may not prevail. <u>Specific Comment 1:</u> The comment on page 4 of the SAR, "The standard should not preclude market solutions (e.g. allow purchasing of response as long as deliverability and restoration criteria can be met).There must be a means for sale/purchase of frequency response as for any other quantity." is workable only in near-normal operating conditions. But it will fail miserably when there is any islanding condition. An analogy: Several skydivers agree that reserve parachutes are a very good idea, but don't want to invest in 1 reserve each. So they agree that they'll buy one to share among them, so each will be saved by that spare. This means that they will hold hands until they pull their ripcords. Sounded good, until they tried it, and the first guy to pull his cord came unhitched, had a failed main 'chute, and the spare was on someone else. <u>Specific Comment 2:</u> The comment on page 4 of the SAR, "The measurement selected must be accurate and, to the extent practical, easy to implement.' may be met in the Eastern Interconnection by the underway DOE "Eastern Interconnection Phasor Project ' and by the similar WECC measurement systems, commonly called "WAMS". Les Peieira's paper, cited in the White Paper, used the WAMS measurements.
Response: The Resources Subcommittee Frequency Task Force appreciates the comments. The proposed standard does not preclude market solutions. The SAR's intent is to define the proposed standard's scope, the actual detail that you recommend will be developed during the standard drafting phase. The phasor projects in both the Eastern and Western Interconnections may indeed be a source of accurate and time stamped frequency data for this standard's application.			

Commenter	Yes	No	Comment
Southern Co. Generation (6) Roman Carter Tony Reed Joel Dison Lucius Burris Lloyd Barnes Clifford Shepard Terry Crawley Roger Green Tom Higgins	✓		It is believed that the industry will be exposing the interconnected electrical systems of North America to a significant degree of reliability risk if a Frequency Response Standard similar to the one proposed by this SAR is not adopted. This risk can be mitigated somewhat by the turbine governor requirements of Standard MOD-014-1 from the Phase III/IV Standards SAR, if passed. However, the risk can be managed properly (and in the most economical manner) on an interconnection/<u>Balancing Authority</u> basis, not on an individual generator basis as required by Standard MOD-014-1. The governor response in MW for generators is not just dependent on the governor droop and dead-band settings, but on the design of the plant control system (sliding pressure boiler, nuclear pressurized water reactor, etc.). For example, nuclear plant operators must control reactivity changes in the core and generally cannot allow external controls to increase or decrease power levels on demand. This standard should take such factors into account and address frequency & MW response at the <u>Balancing Authority level</u>, not at the individual generator level. What is important is that the interconnections maintain sufficient frequency responsive resources to ensure the stability of interconnection frequency under first contingency conditions. The Frequency Response Standard, as proposed, sets requirements for the management and deployment of frequency responsive resources that achieve this goal without unduly interfering with the on going operation of the interconnection. We support this SAR.
Response: The Resources Subcommittee Frequency Task Force appreciates and supports your comments. As envisioned, the standard will measure response at the Interconnection and Balancing Authority level. Only when a Balancing Authority's response measurably below the norm is additional analysis involved.			
MISO Terry Bilke	✓		Thanks for the opportunity to comment. I hope the SAC puts all comments in perspective. We are in a period where the industry is reluctant to adopt new standards that generate extra work and compliance exposure. The reliability of the Interconnections can benefit with minimal impact to most BAs with a light-handed standard. Rather than implementing a complicated process, why not embed most of the effort in the NERC ACE-monitoring application? Only those BAs with unusually low response would need to drill down and do an internal assessment to determine their ability to withstand disturbances and whether they have responsive resources for blackstart. Knowing where and when performance is substandard will likely arrest the decline in performance. Minimum performance standards could be implemented once the industry has identified

Commenter	Yes	No	Comment
			what is reasonably achievable and technically justified.
Response: The Resources Subcommittee Frequency Task Force agrees with these comments.			
New York State Reliability Council (2) Theodore Pappas	✓		The Standard should define the term "event" in terms of time and frequency deviation. The frequency deviation the event must fall outside the droop deadband.
Response: Response: The Resources Subcommittee Frequency Task Force agrees that there should be clear criteria set for identifying events that will be used in calculating frequency response. The SAR was revised to indicate that the standard will require governors to provide droop characteristics within a specified range (to be determined during standard drafting). At this point, the Resources Subcommittee Frequency Task Force recommends each interconnection set a target excursion size that is used for selection of samples and recommends that the target be at least equal to the traditional 36 mHz deadband.			
CAISO (2) Ed Riley Yuri Makarov Steve McCoy		✓	
TXU Electric Delivery (1) Travis Besier or Ellis Rankin		✓	
Progress Energy – Carolinas (1, 3, 5, 6) Phil Creech		✓	
TXU Energy Delivery Roy Boyer		✓	
Robert Blohm		✓	
SPP Operating Reliability Working Group Robert Rhodes –SPP (2) Ron Ciesiel – SPP (2) Bob Cochran – SPS (1) Mike Gammon – KCPL (1) Steve Hillman – WPEK (1) Allen Klassen – Westar (1) Bill Nolte – SECI (1) Mike Stafford – GRDA (1)		✓	
ATC (1) Peter Burke		✓	
Southern Company Transmission, Operations, Planning and			

Commenter	Yes	No	Comment
EMS Divisions (1) Marc Butts Steve Corbin Jim Viikinsalo Jim Griffith Doug McLaughlin Monroe Landrum			
TVA (1) Kathie Davis Larry Akens Mitch Needham Chuck Feagans Ed Forsythe		✓	
Alliant Energy (1) Kenneth A. Goldsmith		✓	
We Energies (3, 4, 5) Howard Rulf		✓	

Background:

The Frequency Response SAR Drafting Team thanks all commenters who submitted comments on the first draft of the SAR for Frequency Response. This SAR was posted for a 30-day public comment period from April 4, 2006–May 3, 2006. The SAR DT asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 16 sets of comments, including comments from more than 59 different people from more than 41 companies representing 6 of the 9 Industry Segments as shown in the table on the following pages.

The primary changes to the SAR were made based on comments:

- Clarification on the role of the LSE and Generator Operator.
- Inclusion of the applicability of Reliability Principles 3, 5 and 6.
- Reduced the scope to address only the collection of data needed to model Frequency Response in North America.

In this 'Consideration of Comments' document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the SAR can be viewed in their original format at:

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

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

Update:

The original SAR on Frequency Response was submitted in large part due to a study that showed a 10+% decline in Eastern Interconnection Frequency Response over a 5 year period, when response should be increasing over time as an Interconnection grows. The drafting team posted a whitepaper along with the SAR to outline the need for a standard.

The NERC Resources Subcommittee recently updated their estimate of Eastern Interconnection Frequency Response and found it to be on the order of 2800MW/0.1Hz and still trending downward.

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

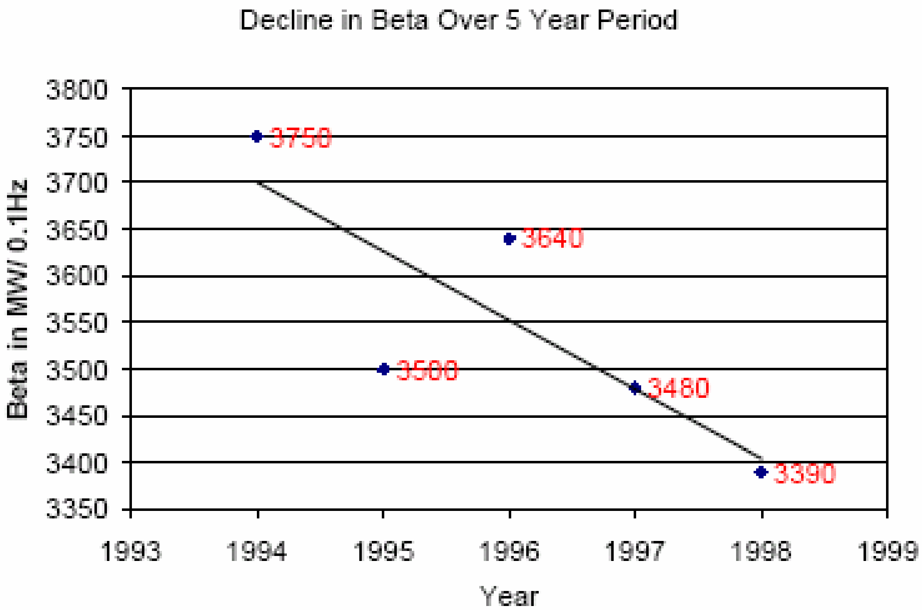

Figure 1 Original Eastern Interconnection Frequency Response Study (Ingleson and Nagle)

Figure 2 Updated Eastern Interconnection Frequency Response (NERC Resources Subcommittee)

Based on these observations, at its June, 2006 meeting, the NERC Operating Committee endorsed developing a frequency response standard that includes the following goals and objectives:

- Improving Interconnection frequency response event cataloging and benchmarking
- Calculating balancing authority frequency response and requiring balancing authorities to analyze those cases where the response is significantly below the norm
- Establishing time limits to complete the analyses

- Tabulating non-responsive generators
- Measuring generator response (including those units on line)
- Including regional participation and review

Unfortunately, the stakeholders who responded to the second draft of the proposed SAR offered a wide range of opinions on what should be in the standard, without a clear consensus. Given this, the drafting team revised the SAR to only require collection of data needed to model frequency response in each of the interconnections. Once frequency response has been modeled and analyzed, the Resources Subcommittee and the industry will be in a better position to recommend specific frequency response targets for each Interconnection.

This revised SAR was reviewed and supported by the NERC Resources Subcommittee on December 4, 2006.

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Ken Goldsmith	ALT		x							
Baj Agrawal	APS	x				x				
Bert Peters	APS	x								
Dave Rudolph	BEPC									
Bart McManus	BPA	x		x		x	x			
John Anasis	BPA	x		x		x	x			
Lynn Aspaas	BPA	x		x		x	x			
Mike Viles	BPA	x		x		x	x			
Greg Tillitson	CMRC		x							
Edwin Thompson	ConEdison	x								
Rhett Trease	Duke (NERC RS)									
Tom Pruitt	Duke Energy Carolinas	x		x		x	x			
Jeffrey T. Baker	Duke Energy Midwest	x		x		x	x			
Howard Illian	Energy Mark, Inc.								x	
Dick Pursley	GRE									
David Kiguel	Hydro One Network	x								
Anita Lee	IESO	x								
Ron Falsetti	IESO (Ontario)		x							
Kathleen Goodman	ISO-New England		x							
Bill Shemley	ISO-New England		x							
Jim Cyrulewski	ITC Transmission	x								
Dennis Florom	LES		x							
Donald Nelson	MA Dept of Energy and Tele.		x							
Tom Mielnik	MEC		x							
Robert Coish	MHEB		x							
Terry Bilke	MISO		x							
Pete Lebro	National Grid	x								
Sydney Niemeyer	NRG Texas LP (NERC RS)									
Alden Briggs	NBSO									
Greg Campoli	New York ISO		x							
James W. Ingleson	New York ISO		x							
Alan Adamson	New York State Rel. Council		x							
Don Badley	NWPP (NERC RS)									
Brian Hogue	NPCC		x							
Guy Zito	NPCC		x							
Alan Boesch	NPPD	x								
Murale Gopinathan	NU		x							

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Mark Kuras	PJM		x							
Joe Willson	PJM		x							
Al DiCaprio	PJM		x							
Robert Johnson	PSC	x								
Rich Cornelius	RDRC		x							
Wayne Guttormson	SaskPower	x								
Tom Botello	SCE	x								
Jim Busbin	Southern Company Services	x								
Jim Viikinsalo	Southern Company Services	x								
Marc M. Butts	Southern Company Services	x								
Raymond Vice	Southern Company Services	x								
Roman Carter	Southern Company Services	x								
J.T. Wood	Southern Company Services	x								
Wayne Guttormson	SPC		x							
John Tolo	TEP (NERC RS)									
Roger Champagne	TransEnergie (Quebec)	x								
Bruce Sembeck	Tri-State Generation and Transmission Association, Inc.	x								
Nancy Bellows	WACM	x								
Darrick Moe	WAPA									
Terry Baker	WECC Reliability Coordination Subc.		x							
Jim Maenner	WPS		x							
Pam Oreschnick	XEL		x							

Index to Questions, Comments and Responses

1. Do you agree that comments from the first posting of the SAR were adequately addressed?

Summary Consideration: Most commenters indicated that the SAR drafting team did provide an adequate response to the comments submitted with the first posting of the SAR.

Commenter	Yes	No	Comment
Energy Mark, Inc. (8) Howard F. Illian		✓	There is an expectation apparent in the first set of responses that indicates that the drafting team believes they have more knowledge of the solutions that will be required than the final standard will contain. The two greatest areas of insufficient understanding lie in the measurement of Frequency Response at less than the full interconnection level and the effect of the standard as envisioned on markets. These two problems are addressed in the comments to later questions in this comment form.
Response: There were varying opinions on the scope of the second draft of the SAR. The drafting team revised the scope of the SAR again to focus solely on collection of data needed to model frequency response in each of the interconnections. Once that data is collected and analyzed, a standard can be proposed that includes performance requirements that will motivate entities to operate in ways that keep frequency response within an acceptable range.			
NPCC CP9 Reliability Standards Working Group K. Goodman – ISONE Edwin Thompson – ConEd Pete Lebro – Ngrid Alan Adamson – NYSRC Bill Shemley – ISONE Ron Falsetti – IESO Murale Gopinathan – NU Ralph Rufrano – NYPA R. Champagne – TransÉnergie David Kiguel – Hydro One Greg Campoli – NYISO Jim Ingleson – NYISO Alden Briggs – NBSO Don Nelson – MA Dept. of Tel. and Energy Brian Hogue – NPCC Guy Vito – NPCC		✓	No - The intent of this SAR is unclear which highlights that this issue requires additional studies and investigation. In the future, it may be beneficial to develop a standard after a reliablity issue is identified, and a specific standard can be developed and implemented to address the issue.

Commenter	Yes	No	Comment
Response: We agree that there needs to be additional studies and investigation. There were varying opinions on the scope of the second draft of the SAR. The drafting team revised the scope of the SAR again to focus solely on collection of data needed to model frequency response in each of the interconnections. Once that data is collected and analyzed, a standard can be proposed that includes performance requirements that will motivate entities to operate in ways that keep frequency response within an acceptable range.			
PJM Corporate Development Div. (2) Al DiCaprio Joseph D. Willson Mark Kuras		✓	The Resources Subcommittee in a response to the first draft states "A primary purpose of this standard is to collect information so informed decisions can be made before there is a problem." It is clear from that reply that the Resources Subcommittee wishes to undertake an analysis of the system and needs to collect additional information. This data collection effort may be laudable but it does not rise to the level of being a federally enforced mandatory standard. What if later on the 'data' were to show there is no problem, then there will be a need to rescind the standard and repay those who were non-compliant to a data collection effort. In their response to the first draft, the Resources Subcommittee cite a WECC study. But they have no similar study for the East. The Resources Subcommittee still has not shown that the decrease in sub-minute response is either (1) a problem or (2) nothing more than an indication that a larger system has more inertia and therefore less response that the smaller system in the past. This SAR, with its present theoretical focus, posits the BA as the responsible entity for governor response. Even those who agreed with the first posting that Frequency Response is an important issue - stated that a standard cannot define fixed norms (MRO, NYISO, IESO (2)). The BA is not responsible to instantaneous response -at best it can establish a capacity obligation but it can't guarantee continuous response.
Response: There were varying opinions on the scope of the second draft of the SAR. The drafting team revised the scope of the SAR again to focus solely on collection of data needed to model frequency response in each of the interconnections. Once that data is collected and analyzed, a standard can be proposed that includes performance requirements that will motivate entities to operate in ways that keep frequency response within an acceptable range.			
IESO (2) Ron Falsetti	✓	✓	Yes, with respect to the responses to the IESO's comments. However, the revised SAR appears to get somewhat mixed up between sub-minute frequency response performance with a longer term (> 1 minute) performance, and lacks clarity on what the proposed standard is intended to stipulate. Is the proposed standard intended to stipulate: (a) a minimum frequency response performance level with which to determine if follow-up analysis is to be conducted, or, (b) requirements for calculating, measuring, reporting and analyzing frequency response, or, (c) both, in addition to, (d) requirements for generators to be equipped with governors and if so, the target to be responding to?

Commenter	Yes	No	Comment
			If (a) is not specified in the standard, we see a difficulty in stipulating the threshold for (b) and the target for (d). From the SDT's response to our previous comments ("The new requirements may need to be field tested for an extended duration before compliance with the requirements becomes mandatory. A long field test with extensive data collection may be needed before justifiable minimum performance standards can be identified"). It is our belief the standard is intended to stipulate (b) only. We see this as a necessary first step. However, it may then beg the question of the need of having a standard to develop the basis for a future standard. Might there not be other alternatives to achieve (b) such as by means of a request from the standing committees or NERC to the BAs and the regions to compile this information?
Response: There were varying opinions on the scope of the second draft of the SAR. The drafting team revised the scope of the SAR again to focus solely on collection of data needed to model frequency response within each interconnection. Once that data is collected and analyzed, a standard can be proposed that includes performance requirements that will motivate entities to operate in ways that keep frequency response within an acceptable range.			
BPA (1, 3, 5, 6) Bart McManus John Anasis Lynn Aspaas Mike Viles	✓		We are still concerned with a NERC standard countering some aspects of the standard we are in the process of drafting in WECC, so will continue to be active on the drafting team to insure it does not adversely impact the WECC standard.
Response: We encourage WECC to be actively involved in the drafting of the standard. Note that the drafting team revised the scope of the SAR so that the SAR focuses solely on the collection of data needed to model frequency response in each interconnection. This should not conflict with WECC's work on its frequency response standard.			
ITC Transmission (1) Jim Cyrulewski Beth Howell Mike Moltane Van Greening	✓		
ATC LLC (1) Jason Shaver	✓		
NERC Resources Subcommittee Raymond Vice – SOCO John Tolo – TEP Rhett Trease – Duke Sydney Niemeyer – Texas	✓		

Commenter	Yes	No	Comment
Don Badley – NWPP Carlos Martinez – CERTS Robert Rhodes – SPP Tom Vandervort – NERC Terry Bilke – MISO Bill Herbsleb – PJM Larry Akens – TVA Bart MaManus – BPA Mike Pitishnak – ISONE Gerry Beckerle – Ameren			
IESO (1) Anita Lee	✓		
Midwest Reliability Organization (2) Terry Bilke Wayne Guttormson Jim Maenner Al Boesch – NPPD (2) Terry Bilke – MISO (2) Bob Coish – MHEB (2) Dennis Florom – LES (2) Ken Goldsmith – ALT (2) Todd Gosnell – OPPD (2) W. Guttormson – SPC (2) Tom Mielnik – MEC (2) Darrick Moe – WAPA (2) P. Oreschnick – XEL (2) Dick Pursley – GRE (2) Dave Rudolph – BEPC (2) Joe Knight – MRO (2)	✓		
Southern Company Transm. (1) Marc Butts	✓		

Commenter	Yes	No	Comment
Raymond Vice Jim Busbin Roman Carter J.T. Wood Jim Viikinsalo			
Southern Company Transm. (1) Marc Butts Raymond Vice Jim Busbin Roman Carter J.T. Wood Jim Viikinsalo	✓		

2. Do you agree with the list of proposed requirements included in the detailed description of the revised SAR?

Summary Consideration: Most commenters disagreed with the proposed requirements included in the second draft of the SAR. The drafting team revised the SAR to focus solely on the collection of data needed to model frequency response in each interconnection. Additional SARs may be proposed in the future to propose requirements for operating in ways that support frequency response.

Commenter	Yes	No	Comment
Arizona Public Service Co. (1, 5) Baj Agrawal			The requirements on individual generator are unnecessary. The requirements should be on a group of generators in a control area to achieve a desired response. Thus, one could have some generators which are being operated as non responsive and the others which are responding well to offset for those which are not responsive. Additionally, the 10 MW size requirements are too restrictive and unnecessary. It should be plant based and should apply to plants of 100 MW or more aggregate capacity. In any realistic scenario, the smaller plants are not expected to contribute much to frequency response and hence subjecting them to frequency response requirements is uneconomic.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional SARs may be proposed with specific performance requirements for generators.			
IESO(1) Anita Lee		✓	The purpose is definitely suggested for under frequency conditions. However, when specifying that the generators shall have governors with droop etc... the role of the governor is for both high and low frequency conditions and not just underfrequency FRR. In a market environment it is very possible that not every generator will provide FRR services. Thus, the governor and governor deadband should be a requirement to interconnect to a power system. Generators that provide FRR shall have responsive governor and prime mover. The standard is based on balancing area response which will include generators and in some jurisdications will include load. So is the intent that whatever load is considered, additional FRR resources such as generators are used to provide the required FRR? What about load as FRR providers? Some industrial facilities are capable to dynamically vary the load of the facility to frequency (ie virtual governor). The standard should apply to FRR providers which can be generators and loads. We agree that generator owners have an obligation to have working governors or provide explanations why not. The "10 MW" requirement should be evaluated for consistency with other standards. This should not hold up the progress of the SAR, but should be evaluated by the ultimate standard drafting team.
Response: The SAR drafting team agrees that governors must work for both high and low frequency events. One methodology under discussion would monitor both high and low events. The logic behind capturing low frequency (typically associated with trips of large generators) is that these events are much more common than large loss of load.			

Commenter	Yes	No	Comment
Any resource (load or generation) within the BA can provide frequency response. As envisioned, the standard would have provided a methodology whereby a BA could monitor its FRR providers. Load, by default, would have been measured along with generators when the BA calculated its performance. We agree that all generators may not need to provide frequency response. As envisioned, as long as the BA had adequate response, it would have had some flexibility under the proposed standard. Note, however, that the SAR has been revised and no longer includes these performance requirements. The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional SARs may be proposed with specific performance requirements for generators. As each new standard is developed, greater attention will be paid on the 'applicability'. The threshold of '10 MW' will need to be reviewed from a reliability-related perspective rather than 'consistency across all standards' perspective.			
IESO (2) Ron Falsetti		✓	The intent of some of the requirements is again unclear to the IESO, for example. (i) Does Bullet #2 mean the flexibility in the calculation and reporting process or in the target/minimum frequency response level? (ii) Assuming Bullet #4 a requirement, and one which relates to the minimum level of frequency response, how is this requirement stipulated at this time while data collection and follow-up analysis are to be proposed as standard requirements and field testing has yet to commence? Same comment applies to Bullet #9. (iii) Bullet #6 appears to go beyond the sub-minute time frame. Further, we are unable to understand the leading sentence "Will not mandate a given amount of frequency response". We feel it is important that if poor frequency response performance in the sub-minute time frame is to be assessed and improved, specific target which may well be the minimum amount of frequency recovery would need to be stipulated. (iv) Bullet #7 also appears to be beyond the sub-minute time frame, which is to mandate AGC but which should be covered by other BAL standards. (v) Bullets #8 and #1 appear to be the main requirements for the proposed standard that are achievable at this time. (vi) As mentioned in (ii) above, we are unable to visualize how the range and target of response be stipulated in the standard before Bullets #1 and #8 are implemented. (v) If generators are allowed to seek exception, the standard should provide some basic premise that bounds the exception cases rather than leaving the door wide open and the decision solely to the judgment of the BAs and RROs.
Response: "Flexibility to meet the needs of each Interconnection" was intended to mean some flexibility in calculation (for example ERCOT is interested in "point C" (the extreme) of an event, but this point is not observable and has little value in the East. The WECC has expressed			

Commenter	Yes	No	Comment
concern for extended contribution of response (perhaps out several minutes). As envisioned, there would have been different target levels in each Interconnection. Interconnections would have been able to choose to have a tighter target droop setting. Bullet 4 relates to a statistically-sound measurement of frequency response at both the Interconnection and BA level. The data would have been collected and reported each year of the standard. In effect, the data collection in the first year of the standard would have served as the field test. “Long term target measure” intended to imply that the BA would be measured on many events over the year and its performance would have been evaluated on the whole, not on single events. It is true operation of AGC goes beyond the sub-minute window of time. The intent of this bullet was that the bias a BA provides should match its natural frequency response. Just as was originally intended in Policy 1, a BA calculates its natural response in one year and uses those observations to operate in the next year. The drafting team envisioned the same would occur in the originally proposed standard. The establishment of the “12 month basis” either on a calendar year or on a rolling 12 month period like CPS1 would have been determined during standard drafting. Note, however, that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional SARs may be proposed with specific performance requirements for generators.			
NPCC CP9 Reliability Standards Working Group		✓	The proposed requirements nor the White Paper adequately make the case that there is a need for a frequency response standard at this time. However, it is recommended that the subject be further investigated. The analysis should evaulate if a frequency response standard that addresses the three major short term frequency control components (inertial response, governor response, and automatic generation control) are required. The report writers should include a broad range of participants including (at least) 3 OEM's (original equipment manufacturers) representing steam, gas and hydro generation control. Some specific issues that should be addressed are: 1. Inertial Response: Evaluate historical changes in the inertial response of the electric grid as a result of changing power equipment designs and types of load. For example, the addition of new industrial and aero-derivative turbine-generators have lower inertia-power ratios than tranditonal nuclear/fossil units and, in addition, they are not base loaded (as a result of more efficient dispatching and improved power plant controls). 2. Governor Response: Evaulate generation governor performance as a result of newer, more configurable prime mover controls. Digital controls provide increased plant reliability, however, this may be at the expense of decreased governor response. For example, the use of main steam pressure controls on steam units and low NOx controls on gas turbines may

Commenter	Yes	No	Comment
			produce unexpected droop output responses. 3. Automatic Generation Control (AGC): Perform a control area survey to determine if there is sufficient regulation capacity within control areas to maintain generation and load balance. Include a review of incentives and penalties for generators to respond accurately and reliably to AGC signals.
Response: When the first draft of the SAR was posted for comment, the drafting team asked stakeholders if they felt that there was a reliability-related need for a standard that focuses on frequency response, and most stakeholders indicated there is a reliability-related need for a frequency response standard. While we don't know the exact amount of frequency response needed for each interconnection, a 12 year decline in response when it is expected to be increasing and without knowledge of where the response is low is a reliability concern. Failure of generators to follow AGC signals would appear to be either a CPS issue or a business practice. The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
Energy Mark, Inc. (8) Howard F. Illian		✓	Requirements that apply to individual generators cannot be implemented as indicated in the standard without failing to comply with Market Interface Principle 2. Frequency Response (Governor Response) have economic costs associated with standing ready to supply. These costs have been documented in EPRI Reports on Ancillary Services. If any generator is given an exception to not provide a response, that generator will also be given a market advantage resulting from the savings they will receive by not providing a response. The SAR as currently written will create a market advantage for all generators below 10 MW and all generators that are given an exception to the governor response requirement. The alternatives to these generator requirements are either not have a competitive market and decide the provision of frequency response administratively (the old VIU method), or determine who provides frequency response through a competitive market process.
Response: We appreciate the comments on Market Interface Principle 2. As envisioned the original SAR proposed measuring the approximately 140 Balancing Authorities rather than the roughly 4000 individual generators (*NERC 2004 Generating Unit Statistical Brochure*). The SAR intended to be indifferent to what entity provides response (whether load, large generator or small generator). It was intended to measure the BA, with the expectation that the BA would have had to document exceptions that would have been reviewed by the BA and the Region for reliability implications. As envisioned, the drafting team did not expect owners to install many small generators rather than one larger generator to avoid providing data for the standard.			

Commenter	Yes	No	Comment
Note that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators.			
Duke Energy Midwest (1, 3, 6) Jeff Baker		✓	Not totally, I need to understand more of what would be required to meet the obligation of Generator owners to equip generating units with nameplate ratings of 10 MW or greater, with a governor capable of providing immediate and sustained response to frequency deviations.
Response: As envisioned, all generators would have governors that respond to frequency deviations. The BA and the Region would need to be aware of exceptions for study purposes. If the BA's performance were significantly below the norm, an analysis and assessment would have been required. Note, however, that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators.			
BPA (1, 3, 5, 6)		✓	RE: bullet 2: Instead of flexibility to meet interconnection needs, each interconnection should have its own requirements on frequency response, this is due to the unique frequency response of each interconnection. re bullet 4: This Standard will need to measure frequency response for the duration of the frequency deviation. Measuring it until frequency recovers will overlap with the Balance Resources and Demand standard slightly, but will give much better results than simply going out a few minutes. re bullet 6: Target levels should be BA specific to insure there is not an incentive to lean on other BA's. How will the target levels be calculated? Re bullet 7: BAs must be free to operate their automatic generation control in any method they desire. The tie-line frequency bias is used for compliance monitoring, but must not be a requirement for the actual automatic generation control algorithm. Recommend this be modified to state: Balancing Authorities will calculate an Area Control Error for monitoring purposes using tie-line frequency bias. re bullet 8: WECC should call FRC surveys for WECC instead of NERC. re bullet 9: Recommend generating unit nameplate of 10 MW plus multi-unit installations of 10 MW or greater be required to have a governor(s) capable of providing immediate and sustained response to frequency deviations. Re bullets 9 and 10: Currently wind generation does not have governor response capability. Due to the amount of wind integration planned in the next decade, new installations should have a requirement for frequency responsive units. Historically, requirements have provided incentive for manufacturers to modify machine design (low-voltage ride-through capability, voltage control capability) to meet the requirements.

<table>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">Response: We agree – the proposed standard would have assumed that each interconnection had a unique frequency response.
Regarding bullet 4, some thought would have to be given on how to measure over the entire duration of a frequency disturbance (typically up to 15 minutes for a DCS event) and how to remove AGC response from the estimate of frequency response. Suggestions are welcome. However, the Interconnection would be able to define specific requirements.

Regarding bullet 8, WECC has the right to call FRC Surveys for WECC, as does NERC (historically through the NERC OC and Resources subcommittee)

We agree with your comment regarding bullet 9.

Regarding wind generation, governor response is normally provided by calling on more energy from the prime mover when frequency drops. We are unsure how this would normally be done with wind, unless the goal would be to under-utilize the wind during normal operation and then call for full available energy when the frequency drops. Again, this standard as originally proposed, was intended to measure BA response- as long as the pool of generation within the BA provided adequate response, it would have allowed the BA flexibility on which generators provide that response.

Note, however, that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.</td></tr>
<tr><td>ATC LLC (1)
Jason Shaver</td><td></td><td>✓</td><td>The SAR identifies Load-Serving Entities as a function that will be affected by any requirements that are developed from this SAR. Question three, on this comment form, goes one step further and asked the industry if the proposed standard would be applicable to Load-Serving Entities. ATC was unable to determine from the detailed description section any requirements that would apply to a Load-Serving Entity. With that being said ATC suggests that language be added to the SAR that would require the Load-Serving Entities to be responsible for procurement of adequate frequency response.
ATC found bullet number six lacks a clear description of the standard that could be developed. ATC recommends that this bullet be rewritten to better inform the industry of the type of standard the SAR requestor wants developed. Is the SAR requestor requesting a standard that will not mandate frequency response, but instead recommend a frequency response? ATC, in general, feels that standards should require something not make recommendation. or, Is the SAR requestor requesting that a standard be develop that would set long-term Interconnection target levels and then require the industry to meet those target-levels? ATC is in support of a standard that would require entities to set long-term target levels and require other entities to meet the determined target levels. ATC is not in support</td></tr>
</table>

Commenter	Yes	No	Comment
			of a standard that requires functions to set long-term target levels but not require other entities to meet those levels. Lastly, this bullet should clearly identify who are the responsible entities. ATC is concerned that Generator Owners could be allowed to categories the same generating units differently. A Generator Owner that aggregates their units for purposes of determining a voltage schedule (VAR-001-1) should then not be allowed to individualize their units for this standard to escape under the nameplate rating of 10 MW.
Response: We agree that the LSE is the ultimate beneficiary of frequency response. However, since the standard isn't mandating a particular amount of frequency response for individual events, it would seem inappropriate to have the LSE obtain a given amount of frequency response for any specific event. As originally proposed, this standard would have been primarily a technical/preparedness standard. Initially, the target levels of frequency response would have been based on observed interconnection history. We agree that bullet # 6 needs additional clarification for it to be understood. The long-term measure was envisioned to be an annual metric, based on a calendar year or on a rolling 12 month basis like CPS1 that captures many events over the year to come up with a composite estimate of performance. It was expected that the standard would allow interconnections to set their own frequency response limits. Absent specific frequency response bounds for an interconnection, the standard would have used recent history. The standard was intended to focus on the frequency response needs of each interconnection, and would have allocated a portion of each interconnection's frequency response responsibility to each of the interconnection's Balancing Authorities. Note that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
PJM Corporate Development Div. (2)		✓	The SAR is still not clear about what is to be developed in the standard. Of the ten bulleted items several seem to show a misunderstanding between a sub-minute frequency response obligation and Automatic Generation control. The RS must make clear what it wants to do. Sub-minute frequency response occurs with or without frequency bias; sub-minute frequency response is not helped or hurt by having AGC. This is a major problem with the proposal. It is not clear and it is not definitive. Item 1 indicates the standard will be a Report Item 2 states the standard will be flexible (that is mandated in the Process Manual) Item 3 seems to indicate that non-compliance will be met with a requirement to analyze the incident (if this is standard is so important why isn't every event critical?) Item 5 is the most unusual - the standard will not mandate a response but will provide

Commenter	Yes	No	Comment
			"LONG-TERM" targets (how is it that a sub-minute response gets translated into a long-term target?) Item 6 is to mandate AGC. This is not related to sub-minute frequency response. Item 7 is to mandate a post-incident survey. Again this is a good idea but it a data collection mandate - it is not a frequency response standard. The RS has the tools to collect that information today, without the need to resort to mandatory penalties. Item 10 will allow generators to seek exceptions (which means that the RS will allow a generator to opt out and still require the BA to comply. In the absurd case that all generators opt out (let's say the BA has only nuclear units) then according to the RS, the BA is held non-compliant. This is just not a good idea. In summary: #1 is a calculation and report on response but no measure of performance; #3 requires a BA and the RRO to perform an analysis if response is measurable (by what amount) below the norm (which is a constantly moving value); #4 is the only possibility for true standard; #9 generators must have governors is more a certification issue than a BA standard. Three of the bullets are not requirements (#2, #5, and #10). Two of the bullets are already in other standards while two of the bullets duplicate each other. The SAR team needs to better describe exactly what is being proposed to be in the standard so that the industry can evaluate the proposal. The industry does not need to get involved in a research project.
Response: The standard was intended to measure response within the first minute (or longer if determined it was needed by the interconnection) following a frequency disturbance (which is prior to the timeframe when AGC contributes to frequency stabilization). Since natural frequency response is much less than Bias for most control areas, AGC will make a contribution to frequency stabilization over a period of time. Regarding item 1, part of this technical/readiness standard was envisioned as a report, much as BAs are responsible to calculate and report CPS or DCS. Refer to the *NERC Reliability Standards Process Manual* for the different types of standards. Regarding item 2, thank you. Regarding item 3, the standard would not have required analysis of single events, but rather performance over a 12-month period. Regarding item 5, as envisioned, the BA would have calculated its response based on several events over the long term (12 months). Interconnection performance is tracked by the Regions and NERC over years. Item 6 refers to using a bias in AGC that is reflective of the BA's natural frequency response. However, based on comments, the Resources Subcommittee agrees this requirement more appropriately belongs in the AGC standard.			

Commenter	Yes	No	Comment
Regarding item 10, the SAR was not proposing that generators may opt out of participation. As envisioned, generators were expected to have governors that respond to frequency. Exceptions would have been documented. Nevertheless, the standard would have measured overall BA response. Note, however, that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
Duke Energy Carolinas (1, 3, 5, 6) Tom Pruitt	✓	✓	Generally, yes, but more clarity is desired on a number of points, e.g., who decides which generators will be granted exemptions - the BA or the RRO; who sets the criteria - BA or RRO. In addition, I think some of the proposed requirements may conflict with each other as details are driven out; if a number of a BA's generators applied for and were granted exemptions from governor response, the (anticipated) 5% droop range may need to be adjusted for the generators which do provide governor response for the BA. Governor response is not the only equipment consideration at the plant/unit. Plant/unit control systems also should be operated so that the desired unit response will occur and be sustained.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
NERC Resources Subcommittee	✓		Re Bullet 7 - BAs must be free to operate their automatic generation control in any method they desire. The tie-line freqeuency bias is used for complinace monitoring, but should not be a requirement for the actual automatic generation algorithm. Recommend this be modified to state : Balancing authorities will calculate an Area Control Error for compliance reporting purposes using tie-line frequency bias.
Response: Based on comments, the Resources Subcommittee recommends this requirement more appropriately belongs in the AGC standard. The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
ITC Transmission (1) Jim Cyrulewski	✓		However some bullets need further clarification Bullet 2: The standards process allows for regional differences. What more flexibility is needed?

Commenter	Yes	No	Comment
Beth Howell Mike Moltane Van Greening			Bullet 6: Keep this bullet simple by simply stating target levels will be set for BAs and RROs to take actions cited. Also a sub-bullet needs to be added on what are options to get additional frequency response; specifically for the BAs. In particular what can the BAs do if the Generation Owners do not provide adequate response. The BAs don't have generation interconnection agreements, the transmission owners do.
Response: As originally envisioned, the primary differences would have been at the Interconnection level. For example, it was envisioned that there might be more than one authorized method that could be used by a BA to calculate response. We agree that transmission owners have interconnection agreements that provide leverage to get generators to perform through "good utility practices" provisions. The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response.			
Midwest Reliability Organization (2)	✓		In particular we agree that generator owners have an obligation to have working governors or provide explanations why not. The 10 MW requirement should be evaluated for consistency with other standards. This should not hold up the progress of the SAR, but should be evaluated by the ultimate standard drafting team.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. Once more is known about frequency response, additional standards may be proposed with specific performance requirements for generators. This will allow analyses to focus on the different types of response and should, eventually, facilitate the development of another standard that includes performance requirements aimed at providing a specified amount of frequency response. With respect to the 10 MW threshold - As each new standard is developed, greater attention will be paid on the 'applicability'. The threshold of '10 MW' will need to be reviewed from a reliability-related perspective rather than 'consistency across all standards' perspective.			
Southern Company Transm. (1)	✓		

3. **Do you agree that the proposed standard(s) would be applicable to the Reliability Coordinator, Balancing Authority, Generator Owner, and Load-serving Entity?**

Summary Consideration: Although most commenters agreed with the proposed applicability, the drafting team has reduced the scope of the proposed standard, and the proposed applicability has been changed. The revised SAR shows that, in addition to the functional entities listed above, the Generator Operator may have some requirements in the proposed standard.

Commenter	Yes	No	Comment
Tri-State G&T (1) Bruce Sembeck		✓	Since the standard is concerned with governor regulated frequency response of generating units that applicability should also apply to the Generator Operator (currently this box is not checked). It will ultimately be the Generator Operators responsibility to ensure frequency responsiveness of the units, e.g. ensuring that the unit is not operating in Valve Wide Open mode.
Response: Note that the SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. We will include generator operator as an applicable entity.			
PJM Corporate Development Div. (2)		✓	This question would require an assumption of what the standard would be. If the standard is to provide sub-minute frequency response, then the only entity should be the generator owner.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection.			
IESO. (2) Ron Falsetti		✓	Not having a good handle on what the standard is intended to achieve and stipulate, we are unable to comment on whom the standard should apply to. Among the ones included in the question, we are unclear on the role of the RC in requiring anyone to install devices or take actions to improve frequency response in day to day operation.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. We expect the Reliability Coordinator's role to be limited (most likely only alerting other Reliability Coordinators of generation or load events causing significant frequency excursions)			
Duke Energy Midwest (1, 3, 6) Jeff Baker		✓	
IESO (1) Anita Lee	✓	✓	The Generator Operator may also have some responsibilities, such as the selection of control modes. We're not sure what the LSE can do regarding the standard. They cannot control response from load. The exception may be coordination of frequency response with UFLS. Planners may have some responsibilities with regard to new interconnections and also using observed frequency response in models as opposed to theoretical response.

Commenter	Yes	No	Comment
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The LSE does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
BPA (1, 3, 5, 6)	✓	✓	The only portion we can think of that would applicable to the Load-serving entity is for the load-serving entity to report their underfrequency load shedding settings. We believe LSEs should be removed as applicable entities.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The LSE does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
Duke Energy Carolinas (1, 3, 5, 6) Tom Pruitt	✓		However, the standard applies to each entity in different ways. The lion's share of responsibility lies with the BA to insure that the aggregate of the Gen Owners responses provide the response needed.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection.			
WECC Reliability Coordination Subc.	✓		The only portion we can think of that would applicable to the Load-serving entity is for the load-serving entity to report their underfrequency load shedding settings. We believe LSEs should be removed as applicable entities.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The Load-serving Entity does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
ATC LLC (1) Jason Shaver	✓		Please see comment in questions two about the Load-serving Entity.
Response: Please see the response to your comment on question 2.			
Midwest Reliability Organization (2)	✓		The Generator Operator may also have some responsibilities, such as the selection of control modes. We're not sure what the LSE can do regarding the standard. They cannot control response from load. The exception may be coordination of frequency response with UFLS. Planners may have some responsibilities with regard to new interconnections and also using observed frequency response in models as opposed to theoretical response.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The Load-serving Entity does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
NERC Resources Subcommittee	✓		The proposed standards may apply to LSEs when demand side resources are utilized for frequency control, but will not apply to many of the LSEs. There may also be cases where Generator Operators have obligations under the standard.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The Load-serving Entity does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
Energy Mark, Inc. (8)	✓		The requirements applicable to the Generator Owner and Load-serving Entity may only

Commenter	Yes	No	Comment
Howard F. Illian			include requirements for measurement processes, not necessairly requirements to provide any frequency response.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. The Load-serving Entity does need to provide some of this data and is listed as an applicable entity in the revised SAR.			
NPCC CP9 Reliability Standards Working Group	✓		If required.
Response: Thank you.			
ITC Transmission (1) Jim Cyrulewski Beth Howell Mike Moltane Van Greening	✓		Also pertains to Generator Operator.
Response: The SAR was revised and will address only the collection of data needed to model frequency response in each interconnection. In the revised SAR, the Generator Operator is responsible for providing data when the BA's performance is below an Interconnection target.			
Southern Company Transm. (1)	✓		

4. **The current standard on Bias requires a Balancing Authority to carry a minimum bias equal to 1% of peak load. As an example, in the Eastern Interconnection, this value is double current natural frequency response. Should the standard provide an incentive, such that a Balancing Authority can use a bias equal to their natural response, but less than 1% of peak, if the response is above an acceptable target?**

Summary Consideration: While most commenters supported this suggestion, there was not consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. The drafting team will forward these comments to the Director of Standards Development so that they can be addressed by the Balance Resources and Demand standard drafting team or another drafting team. This shall serve as a summary response to all comments provided.

Commenter	Yes	No	Comment
IESO. (2) Ron Falsetti		✓	(i) The question seems to get the sub-minute and longer-term targets intertwined. We are unclear on which "standard be provided an incentive". Is it the proposed sub-minute standard which has yet to be determined or the current standard on Bias? If it is the former, then this question seems a bit premature as we don't even know what the performance target for sub-minute response should be. If it's the latter, then the issue belongs to other BAL standards.
		✓	The RS again is avoiding the issue of what sub-minute frequency response it MUST mandate. The 1% is related to the frequency bias setting (basically a long term average response). The BRD deals with the longer term issue of frequency response - this standard was designed for the shorter-term response. If the RS is willing to accept under-biased systems then it would seem to be going against conventional wisdom, and should explain why it would even consider such an idea. If the real intent of this frequency SAR is to establish a minimum frequency response value then the SAR needs to state that. Perhaps the SAR should establish a minimum 1 minute response for every generator (if they can't provide it they are obligated to contract for it from another unit) and maybe a 1 minute average over a week, month, or year if a longer term value is needed. However, since the SAR authors state the problem is sub-minute response, it is suggested that the long term response is better be addressed by the BRD standard. In addition the SAR does not adequately address the load portion of the frequency response. The standard seems to presuppose the solution is having governors.
BPA (1, 3, 5, 6)	✓	✓	The standard should not provide an incentive, but the standard should provide a methodology that would allow a Balancing Authority to calculate a bias based on their natural response, provided that response is above an acceptable target.

Commenter	Yes	No	Comment
Southern Company Transm. (1)	✓		The 1% minimum frequency bias is obsolete and does not take into account the changes in interconnection frequency response over recent years. If not modified, it will lead to increased frequency oscillations within the interconnections and needless maneuvering of generating assets with associated wear and tear on these assets.
IESO(1) Anita Lee	✓		There should be a safeguard in place, such that if frequency performance declines, the industry reverts to the 1% minimum.
Midwest Reliability Organization (2)	✓		There should be a safeguard in place, such that if frequency performance declines, the industry reverts to the 1% minimum.
Energy Mark, Inc. (8) Howard F. Illian	✓		There is a minimum frequency response below which the interconnection will be less reliable than acceptable. We currently do not know what this value is but we do know that a value exists. We also know that this value is less than the 1% of peak load specificed in the current standards. A standard that arbitrairly requires a 1% of peak load response without a technical justification based on reliability cannot be called a reliabiltiy standard. However, even though we do not know the minimum frequency response below which the interconnection will be less reliable than acceptable, we can perform the work necessary to estimate a reasonable value for a minimum frequency response and assign responsibility for that response among the Balancing Authorities on an interconnection. A Frequency Response Standard without this characteristic cannot maintain reliability of the interconnection.
Duke Energy Midwest (1, 3, 6) Jeff Baker	✓		I believe that an incentive should be included in the standard.
Duke Energy Carolinas (1, 3, 5, 6) Tom Pruitt	✓		Calculation of each BA's bias should be based on a rigorous analysis which demonstrates that the BA can provide the expected response, regardless of peak load. This is consistent with the proposed requirements - 'technically-sound calculation and report of frequency response' and 'Will not mandate a given amount of frequency response'.
ATC LLC (1) Jason Shaver	✓		Although ATC is in support of this recommendation, we feel that it should be classified as an "allowable exemption" not an "incentive".
NERC Resources Subcommittee	✓		The 1% minimum frequency bias should be evaluated to take into account the reliability requirements of the interconnections. frequency response over recent years. We suggest that the minimum bias be addressed during the development of the Frequency Response Standard. It is unclear what the word "incentive" means above.
ITC Transmission (1) Jim Cyrulewski Beth Howell	✓		However this requirement still does not address the need for enough frequency response on the system.

Commenter	Yes	No	Comment
Mike Moltane Van Greening			

5. **Several commenters suggested response should be measured for an extended period after a frequency excursion, up to the point where automatic generation control (AGC) would take over. This was to ensure initial response wasn't withdrawn prematurely. Should the standard measure out to 60 seconds following an excursion?**

Summary Consideration: There was not consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. The drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This window may be reduced during the standard drafting phase. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by Automatic Generation Control action.

Commenter	Yes	No	Comment
Duke Energy Midwest (1, 3, 6) Jeff Baker			I did not provide an answer but believe that this is a decision that could be made over time and not necessarily with the inception of the standard.
Response: We agree.			
Arizona Public Service Co. (1, 5) Baj Agrawal		✓	Most of the frequency recovery happens in first 30 seconds. Thus anything more than 30 seconds is unnecessary. It is also seen that the response of a unit varies greatly within that 30 seconds period. Thus, it is very important that the measured response be the average response over the 30 seconds period and not be the response at 30 seconds.
Response: We agree that frequency response should be measured over a period of time (as opposed to a measure for a single event).			
Southern Company Transm. (1)		✓	AGC response begins within only a few seconds after the disturbance with a maximum ramp rate achieved within three to five minutes. Governor response and load frequency response typically peak within 30 seconds. There is some logic to monitoring governor respone for sustainability past its initial peak, but we have not seen anything about that in this SAR.
Response: There was no consensus on this matter. The drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
		✓	The standard should measure out to when the frequency recovers. This could be up to the 15 minute DCS limit. AGC control may or may not kick in within 60 seconds depending on deadbands, etc. However, generators on setpoint control may hold for between 10 and 60 seconds then drop back off prior to AGC pulses reaching the generator. In order to see the full response of a BA it is necessary to see data for the full event rather than just the first minute. Rather than overlapping the BRD standard, this will work hand-in-hand with this standard.
Response: There was no consensus on this matter. The drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window			

Commenter	Yes	No	Comment
of time where frequency response appears to be masked by AGC action.			
NPCC CP9 Reliability Standards Working Group		✓	This question is not clear. AGC control pulses generation every 5 seconds, therefore, the measurement should be based on the amount of time it takes to restore the generation load balance.
Response: In general, following a unit trip, frequency will not recover until the contingent BA has replaced the energy that was lost. This typically takes up to 15 minutes. Unless over-biased, a non-contingent BA will not contribute AGC response to a frequency event.			
PJM Corporate Development Div. (2)		✓	Unsure as to what is being suggested here. The SAR drafters need to be specific about what requirements are needed and how they will be measured. The details contained in the white paper are supporting information but they do not define the standard that is being proposed.
Response: There was no consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections.			
NERC Resources Subcommittee	✓	✓	AGC response begins within only a few seconds after the disturbance with a maximum ramp rate achieved within three to five minutes. Governor response and load frequency response typically peak within 30 seconds. There is logic to monitoring governor response for sustainability past its initial peak and this should be investigated during standard development.
Response: We agree with this comment. The drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
IESO(1) Anita Lee	✓		Sixty seconds is a reasonable balance to capture the period prior to AGC response.
Response: Agree – However, several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
IESO. (2) Ron Falsetti	✓		This should cover the entire spectrum of immediate response before AGC kicks in.
Response: Agree However, several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
Energy Mark, Inc. (8) Howard F. Illian	✓		There are two issues associated with this question. The first is that the change in instantaneous frequency be limited to within a range that limits the risk of a cascading outage on the interconnection. The second is that each generation technology provides a different response characteristic within the first minute after a sudden frequency excursion. Work

Commenter	Yes	No	Comment
			performed at NIPSCo and published by IEEE indicated that a measurement interval of one to two minutes worked well for the measurement of frequency response. Without specific knowledge of the nature of the individual responses that make up the sustained frequency response to an excursion, it may be difficult to justify the selection of a measurement interval shorter than one-minute that might put some generation technologies at a disadvantage with respect to the measurement method. This is a subject that the drafting team should technically evaluate before including a specific measurement period in the standard.
Response: Several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
Duke Energy Carolinas (1, 3, 5, 6) Tom Pruitt	✓		At least. Based on the words in the SAR Purpose statement, 'this proposed standard coordinates with and complements the Balance Resources and Demand standards, which addresses Interconnection frequency control generally 5 minutes and longer', it seems that this standard should cover out to the 5 minute mark of an event. AGC actions will commence at the first scan cylcle or two after the event (5 -15 secs), but the actual generation response may not settle out for several minutes, depending on the type and amount of generation on AGC at the time.
Response: Several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
Midwest Reliability Organization (2)	✓		This is a significant issue, because if the governor system withdraws the unit's support prior to the recovery of frequency, this does have a problematic impact. A period of at least 60 seconds should be considered, and 60 seconds may not be adequate as often frequency recovery of the interconnection extends beyond the initial 60 seconds.
Response: Several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action.			
ITC Transmission (1) Jim Cyrulewski Beth Howell Mike Moltane Van Greening	✓		Needs to be verified with a field trial.
Response: Several commenters indicated there may be value in analyzing response for several minutes and the drafting team modified the SAR to specify that data will be collected to measure response over a period up to 5 minutes. This should provide sufficient data to analyze frequency response and should help identify the window of time where frequency response appears to be masked by AGC action. Note that the			

Commenter	Yes	No	Comment
drafting team modified the scope of the entire SAR to focus solely on collecting data needed to model frequency response in each of the interconnections.			
ATC LLC (1) Jason Shaver	✓		

6. Do you have other comments on the SAR?

Commenter	Comment
ITC Transmission (1) Jim Cyrulewski Beth Howell Mike Moltane Van Greening	Reliability and Market Interface Principles 3, 5 and 6 should be checked as well.
Response: We made this change.	
PJM Corporate Development Div. (2)	Please be clear about the terminology. Frequency response comes in many flavors - sub-minute; several minutes; and hours. The RS seems to touch on all of them in this proposal.
Response: There was no consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. The data collection will include data to model and analyze frequency response up to five minutes.	
Southern Company Transm. (1)	In our opinion, this SAR, or one like it, is required to ensure that the primary frequency response of the interconnections and the BAs do not deteriorate to a point where 1) the interconnection can not adequately respond to major generator trips (including potential multiple contingencies which, though rare, do happen) and 2) primary frequency response of the BAs is inadequate to support islanding during severe local disturbances, thus allowing local disturbances to cascade into regional or interconnection wide disturbances. Primary frequency response is declining in at least the Eastern and Western Interconnections. WECC has taken a proactive approach to addressing this problem, but there is no similar work being done in the Eastern Interconnection. This SAR, or one like it, is needed to take the best practices in the industry, wherever they may be found, and utilize them to protect the interconnections from disturbances that could be avoided if we take action now rather than waiting until the problems actually occur.
Response: There was no consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. Your support is very much appreciated.	
IESO. (2) Ron Falsetti	(i) The SAR does not address the load portion of the frequency response but it indicates that the standard would apply to the LSEs as well. Please clarify or eliminate LSE from the Reliability Function check list. (ii) We feel that the SAR needs to be very clear on what the proposed standard is intended and what will be included. Conducting calculation, measuring and report on frequency excursion events followed by analysis would help to ascertain whether or not poor performance exists. However, the determination of poor performance also relies on having a minimally acceptable level to gauge. If the standard is to provide requirements for calculation, reporting and conducting analysis only, then there

Commenter	Comment
	needs to be some general guideline on the threshold for reporting and analyzing, which in turn begs the question of should this "guideline" be included as the initial standard, whose compliance would not be enforced until sufficient experience has been gained and field test conducted, with possible revision as experience and field test so suggest. Absent a minimum performance level, the requirements for governor setting would be difficult to determine.
Response: There was no consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. The Load-serving Entity will need to provide some of the data needed to model frequency response.	
Energy Mark, Inc. (8) Howard F. Illian	The current measurement methods for determining individual Balancing Authority Frequency Response may not be reliable. This is because the current measurement methods only capture a small sample of the frequency responses provided limited to only several minutes per year. The metering methods we currently use on the interconnection can shed some light on this problem. Since the each BA measures its Tie Line Error with common metering with adjancent BAs, the sum of the Tie Line Errors over the total interconnection must equal zero at all times. Each tie line has a positive error for one BA and a negative error of equal value to the other BA that the tie line connects. If the errors must sum to zero, then the change in errors must also sum to zero between any two points in time. Since the Frequency on an interconnection is the same throughtout the interconnection at any point in time for the purpose of the frequency response measurement, the change in frequency between two points in time must also be the same throughout the interconnection. Therefore, the change in tie-line error divided by the change in frequency must indicate a total frequency response for the interconnection as measured by the sum of the individual BA frequency responses must be equal to zero. In other words, there is a BA or a set of BAs that cause each frequency response on the interconnection. Only knowledge of the distribution of individual frequency responses among BAs will provide the necessary information to determine whether or not the frequency response indicated by current measurement methods will maintain adequate reliablity. It may not be the average frequency response to large events that indicates interconnection reliability, but the distribution of frequency responses among BAs including both the positive and negative responses. Therefore, the measurement methods included in the standard should have the goal of capturing the distribution of both positive and negative frequency responses over the entire range of frequency operation should be a goal of standard. The measurement methods suggested will not accomplish this goal.
Response: We agree with the concerns on errors induced in the measurement process. The standard will be designed to capture enough events to provide a statistically-sound estimate of Balancing Authority response. We also agree that the distribution of responses needs to be considered.	
Duke Energy Midwest (1, 3, 6) Jeff Baker	I believe we have to address the frequency issue, but feel that it can be developed over time proactivly.
Response: The revised SAR focuses solely on the collection of data needed to model frequency response. The data can be analyzed and additional standards can be developed that build on the results of those analyses. This supports your suggestion that the standard(s) be	

Commenter	Comment
developed proactively over time.	
NERC Resources Subcommittee	In our opinion, this SAR, or one like it, is required to ensure that the primary frequency response of the interconnections and the BAs do not deteriorate to a point where 1) the interconnection can not adequately respond to major generator trips (including potential multiple contingencies which, though rare, do happen) and 2) primary frequency response of the BAs is inadequate to support islanding during severe local disturbances, thus allowing local disturbances to cascade into regional or interconnection wide disturbances. Primary frequency response is declining in all Interconnections, Eastern, Western and ERCOT. WECC and ERCOT have taken a proactive approach to addressing this problem, but there is no similar work being done in the Eastern Interconnection. This SAR, or one like it, is needed.
Response: There was no consensus on the scope of the proposed requirements, and the drafting team revised the SAR to focus solely on collecting data needed to model frequency response in each of the interconnections. Your support is very much appreciated.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 3rd Posting of Frequency Response SAR

The Frequency Response SAR Requesters thank all commenters who submitted comments on Draft 3 of the Frequency Response SAR. This SAR was posted for a 30-day public comment period from February 8 through March 9, 2007. The requesters asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 26 sets of comments, including comments from more than 59 different people from 39 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team did not make any changes to the SAR (except to update the descriptions of the Reliability Functions to match the latest version of the Functional Model) and is recommending that the Standards Committee authorize moving this SAR forward to standard drafting.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

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

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

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

The Industry Segments are:

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Dan Boezio (G8)	AEP	✓									
2.	Jason Shaver	American Transmission Co.	✓									
3.	Bart McManus	Bonneville Power Administration	✓									
4.	James Murphy	Bonneville Power Administration	✓									
5.	John Anasis	Bonneville Power Administration	✓									
6.	Brenda Anderson	Bonneville Power Administration	✓									
7.	Brent Kingsford	California ISO		✓								
8.	Ed Thompson (G2)	ConEd	✓									
9.	Michael Gildea	Constellation Generation					✓					
10.	Doug Hils (G3)	Duke Energy	✓									
11.	Howard F. Illian	Energy Mark, Inc.								✓		
12.	Steve Myers (G1)	ERCOT		✓								
13.	Bruno Jesus (G2)	Hydro One Networks	✓									
14.	Roger Champagne (G1)	Hydro Québec TransÉnergie	✓									
15.	Ron Falsetti (G1)	IESO		✓								
16.	Kathleen Goodman (G1)	ISO-NE		✓								
17.	Bill Shemley (G2)	ISO-NE		✓								
18.	Brian Thumm (G3)	ITC Transmission	✓									
19.	Jim Cyrulewski (G3)	JDRJC Associates								✓		
20.	Michael Gammon	Kansas City Power & Light	✓									
21.	Jim Useldinger	KCPL	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
	(G8)											
22.	Jason Atwood (G8)	Kelson Energy				✓						
23.	Don Nelson (G2)	MA Dept. of Tele. And Energy									✓	
24.	Robert Coish	Manitoba Hydro	✓		✓		✓	✓				
25.	Alan R. Oneal	MidAmerican Energy Co.										
26.	Jason Marshall (G3)	Midwest ISO Stakeholders Standards Collaboration Participants		✓								
27.	Herb Schrayshuen	National Grid	✓									
28.	Randy McDonald (G2)	NBSO		✓								
29.	Guy V. Zito (G2)	NPCC										✓
30.	Sydney Niemeyer	NRG Texas, Qualified Scheduling Entity					✓					
31.	Jerad Barnhart	NStar	✓									
32.	Mike Calimano (G1)	NYISO		✓								
33.	Greg Campoli (G1)	NYISO		✓								
34.	Ralph Rufrano (G2)	NYPA	✓									
35.	Theodore Papaps	NYSRC										✓
36.	Al Adamson (G2)	NYSRC										✓
37.	Pete Kuebeck (G8)	OG&E	✓									
38.	Al DiCaprio	PJM		✓								
39.	Alicia Daughtery	PJM		✓								
40.	Joseph Willson	PJM		✓								
41.	Tom Bowe	PJM		✓								
42.	Mike Pfeister	Salt River Project	✓									
43.	Jim Busbin (G6)	Southern Company Services, Inc.	✓									
44.	Marc Butts (G6)	Southern Company Services, Inc.	✓									
45.	J.T. Wood (G6)	Southern Company Services, Inc.	✓									
46.	Roman Carter	Southern Company Services, Inc.	✓									
47.	Raymond Vice	Southern Company Services, Inc.	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
48.	Jim Viikinsalo	Southern Company Services, Inc.	✓									
49.	Tom Higgins	Southern Company Services, Inc.					✓					
50.	Terry Crawley	Southern Company Services, Inc.					✓					
51.	Ron Beck	Southwestern Power Administration	✓									
52.	Bill Grant (G8)	Southwestern Public Service	✓									
53.	Wayne Galli (G8)	SPP										✓
54.	Steve Massey (G8)	Westar Energy					✓					
55.	Mich Crouch (G8)	Western Farmers	✓									
56.	Greg Pieper	Xcel Energy Services	✓									
57.	Michael Ibold	Xcel Energy Services			✓							
58.	Steve Beuning	Xcel Energy Services					✓					
59.	David Lemmons	Xcel Energy Services						✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 - IRC Standards Review Committee
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Midwest ISO Stakeholders Standards Collaboration Participants (MISO SSC)
G4 – TVA
G5 – Public Service Commission of SC (PSC of SC)
G6 – Southern Company Transmission (Southern Co)
G7 – MRO
G8 – Southwest Power Pool Operating Reliability Working Group

Index to Questions, Comments, and Responses

1. **Do you agree with the reduced scope of this SAR — focusing only on the data collection needed to support the development of accurate models of Frequency Response in North America?**

Summary Consideration:

The majority of the comments agreed with the reduced scope of the SAR, which now focuses only on the data collection that is needed to support the development of accurate models of Frequency Response in North America. For most of the commenters that did not support the reduced scope, the SAR Drafting Team believes there may be a misunderstanding with respect to the use of the Target Frequency Response. The SAR Drafting Team explained to those commenters that the Target Frequency Response does not set a minimum for any particular Balancing Authority. Rather it sets a benchmark, beyond which additional data is needed from the Balancing Authority.

Question #1			
Commenter	**Yes**	**No**	**Comment**
SWPA		☑	The scope of this SAR is for data collection, and should not include establishing a Target Frequency Response as stated in Paragraph #5.
Response: The SAR Drafting Team appreciates your input, but disagrees with your conclusion. There should always be a purpose for going to the trouble and expense of capturing and analyzing data. The SAR Drafting Team considers the establishment of a Target Frequency Response for each Interconnection as vital for the reliability of the Interconnections and one of the two fundamental reasons why this SAR was initially drafted. The SAR Drafting Team believes there may be a misunderstanding with respect to Target Frequency Response, which does not set a minimum for any particular Balancing Authority. The Target Frequency Response sets a benchmark, beyond which additional data is needed from the Balancing Authority.			
Xcel Energy Services		☑	We agree with the proposed scope except that items 5 and 6 do not deal specifically with data collection and therefore are beyond the scope of the SAR. We are concerned over establishing a Target Frequency Response. This is presumptious in that it advances a proposed remedy before first meeting the intent of the SAR-determining the cause for the percieved decline in frequency response. We support Items 6a. and 6b. if referenced to item 4 as modified as follows: Modify 4 to require generator level reporting when the Frequency Response for a BA is less than [75]* percent of the Previous Years observed Frequency Response. Delete items 5 and 6.
Response: In response to your first comment on Paragraph 5, the SAR Drafting Team considers the establishment of a Target Frequency Response for each Interconnection as vital for the reliability of the Interconnections and one of the two fundamental reasons why this SAR was drafted initially. The reason for establishing the target frequency response is to determine the point at which additional data is needed from a given Balancing Authority. In response to your comment on Paragraph 6, the SAR Drafting Team does not view the provisions of Paragraph 6 as presumptive or proscriptive, but as a necessary step in identifying and understanding potential frequency response variations within a given Interconnection. No specific action is required by the Balancing Authority or the Generation Owner at this			

Question #1			
Commenter	**Yes**	**No**	**Comment**
point in the process beyond supplying the data needed for NERC to understand why variations in Frequency Response occur in different regions and to determine if further actions are required, via the NERC Reliability Standards Process, to address them.			
PJM		☑	The primary objective of this SAR is to collect data; to analyze the data; and only then to recommend a performance value. The SAR DT insists that collecting data is a Technical Standard. The RSDP states: "Technical standards…will contain Measures (not measuring - AMD) of physical parameters…" At this point this SAR proposal does not contain such a measure, it does not even assert that the measure is really needed (hence the need to analyze the data). Page 19 (of 43) of the RSPM states "The drafting team may recommend the scope of the standard be reduced to allow the effort to move forward, while still remaining within the scope of the SAR. Reducing the scope of the SAR is acceptable if the drafting team finds, for instance, THAT ADDITIONAL TECHNICAL RESEARCH IS NEEDED PRIOR TO DEVELOPING (emphasis added) a portion of the standard or issues need to be resolved before consensus can be achieved on a portion of the standard. "The highlighted section applies directly to the scope of this SAR. The SAR Team recognizes work is needed. There is no question about that. The Team should do that work BEFORE proposing a mandatory standard. PJM supports the concept of doing such a study, and would encourage NERC to assign a group to do such a study, but PJM does not agree that collecting data rises to the level of a valid NERC reliability standard.
Response: NERC's Reliability Standards Development Plan: 2007 - 2009 describes the characteristics of a Reliability Standard as follows: " Although reliability standards have a common format and process, several types of reliability standards may exist, each with a different approach to measurement: ▪ **Technical standards** related to the provision, maintenance, operation, or state of bulk power systems will likely contain measures of physical parameters and will often be technical in nature. ▪ **Performance standards** related to the actions of entities providing for or impacting the reliability of the bulk power systems will likely contain measures of the result of such actions, or the nature of the performance of such actions". Collecting, correlating and analyzing data on a continental scale is not a simple matter. The SAR Drafting Team believes that the scale of this project and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6 more than warrant the use of the NERC Reliability Standards Process to address them. Directed research can be			

Question #1			
Commenter	**Yes**	**No**	**Comment**
investigated during the standard development effort.			
IESO		☑	We do not agree with the reduced scope of this SAR. It does not require a standard to enable a data collection task(s). Data collection procedures and processes, charged by a standing committee, e.g. the OC, or respective working groups, would be more than sufficient.
Response: The SAR Drafting Team believes that the scale of this project, the ongoing nature, and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6 more than warrant the use of the NERC Reliability Standards Process to address them. We believe the Standing Committees would play a vital role in evaluating the initial results of the standard.			
SPP ORWG		☑	Do not agree with the notion in point 5 regarding the need for a Target Frequency Response for each interconnection at this time. It is beyond the scope of this technical SAR to propose anything other than collection of data to support the study. Do not agree with point 6 of the description. In order to get a handle on what is really going on, all Balancing Authorities should be required to produce data valid to the study. Also the language in point 6 is poorly worded compared to the right wording in 6a and 6b. 6a and 6b should be included in the SAR and 6 should be removed.
Response: The SAR Drafting Team appreciates your input, but disagrees with your conclusion. The SAR Drafting Team considers the establishment of a Target Frequency Response for each Interconnection as vital for the reliability of the Interconnections and one of the two fundamental reasons why this SAR was drafted initially. The reason for establishing the target frequency response is to determine the point at which additional data is needed from a given Balancing Authority. With respect to your comment on Paragraph 6, the SAR Drafting Team does not view the provisions of Paragraph 6 as presumptive or proscriptive, but as a necessary step in identifying and understanding potential frequency response variations within a given Interconnection. No specific action is required by the Balancing Authority or the Generation Owner at this point in the process beyond supplying the data needed for NERC to understand why variations in Frequency Response occur in different regions and to determine if further actions are required, via the NERC Reliability Standards Process, to address them. The intent of the Target Frequency Response is to determine the point where additional data is required. The SAR Drafting Team does not recognize the specific wording that you are referring to in Paragraph 6 and request clarification.			
KCP&L		☑	Do not agree with the notion in point 5 regarding the need for a Target Frequency Response for each interconnection at this time. It is presumptuous to advance a remedy prior to determining cause of the perceived decline in frequency response. Allow the techincal SAR to perform its function to determine cause. Any appropriate remedy in operating standards should become apparent. Do not agree with point 6 of the description. In order to get a handle on what is really

Question #1			
Commenter	**Yes**	**No**	**Comment**
			going on, all Balancing Authorities should be required to produce data valid to the study. Also the language in point 6 is poorly worded compared to the right wording in 6a and 6b. 6a and 6b should be included in the SAR and 6 should be removed.
Response: We appreciate your input, but disagree with your conclusion. The SAR Drafting Team considers the establishment of a Target Frequency Response for each Interconnection as vital for the reliability of the Interconnections and one of the two fundamental reasons why this SAR was drafted initially. The reason for establishing the target frequency response is to determine the point at which additional data is needed from a given Balancing Authority. In response to your comment on Paragraph 6, the SAR Drafting Team does not view the provisions of Paragraph 6 as presumptive or proscriptive, but as a necessary step in identifying and understanding potential frequency response variations within a given Interconnection. No specific action is required by the Balancing Authority or the Generation Owner at this point in the process beyond supplying the data needed for NERC to understand why variations in Frequency Response occur in different regions and to determine if further actions are required, via the NERC Reliability Standards Process, to address them. The intent of the Target Frequency Response is to determine the point where additional data is required. The SAR Drafting Team does not recognize the specific wording that you are referring to in Paragraph 6 and request clarification.			
Hydro Québec TransÉnergie	☑	☑	HQT believe there might be other means than Reliability Standards to accomplish this data collection.
Response: The SAR Drafting Team agrees that there may be methods other than the use of the NERC Reliability Standards Process to address this issue. However, due to the scale of this project and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6, the SAR Drafting Team believes that the use of the NERC Reliability Standards Process is appropriate.			
NPCC CP9	☑	☑	Many of NPCC's participating members believe there are other means to accomplish this phase of the initiative and that appropriate revisions to existing standard(s) may address the issue determined by the data analysis could be proposed.
Response: The SAR Drafting Team agrees that there may be methods other than the use of the NERC Reliability Standards Process to address this issue. However, due to the scale of this project and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6, the SAR Drafting Team believes that the use of the NERC Reliability Standards Process is appropriate.			
NYISO	☑	☑	The NYISO is uncertain if this is the appropriate means to require data collection for purposes of developing models. A review should be made to be certain that this proposed scope meets the criteria for a standard.
Response: The SAR Drafting Team agrees that there may be methods other than the use of the NERC Reliability Standards Process to address this issue. However, due to the scale of this project and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6, the SAR Drafting Team believes that the use of the NERC Reliability Standards Process is appropriate. Note that the NERC Standards Committee and the industry as a whole are currently performing just such a review, as you request, by commenting on this draft SAR.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Energy Mark, Inc.	☑		At this time information is not available that would provide a sound technical basis for the development of a performance standard. However, with the recent increased interest in Frequency Response, new data and analysis could become available at any time that would change the focus from a technical standard to a performance standard. If new information and analysis becomes available during the development of the technical standard, consideration should be given to how the development of the technical standard could delay the development and implementation of a performance standard. Must the technical standard be completed and approved before work can start on a performance standard?
Response: The SAR Drafting Team agrees that there may be technical issues which may allow the Standard Drafting Team to accomplish the functional purpose of this SAR differently than anticipated by the SAR Drafting Team. This is allowed for in the NERC Reliability Standards Process Manual, page 19, as noted by PJM above. It is anticipated by the SAR Drafting Team that the work set forth in the SAR will aid in determining if a Performance Standard is required and, if so, how the standard should be structured. A SAR for a Frequency Response Performance Standard can be written and submitted to the NERC Standards Committee at any time.			
MidAmerican Energy Co.	☑		This standard would be a start, at least, at bringing to light where and why response is being lost. It may well be that exposure and peer pressure, as well as the tiered reporting requirements, will keep plant and operations personnel abreast of their obligations for providing reserves of all types.
Response: The SAR Drafting Team appreciates your support.			
Southern	☑		Frequency response and its dynamic behavior is a complex issue that requires detailed analysis and study to understand. This in turn requires sufficient high quality data be obtained to support the development of models and concepts. The data could be collected voluntarily, but without the force of NERC standards behind it not many people are going to devote the resources required to collect the data. We strongly support this effort.
Response: The SAR Drafting Team appreciates your support.			
ISO New England	☑		
Bonneville Power Administration	☑		
American Transmission Co.	☑		
CAISO	☑		
ERCOT	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		
MISO	☑		
NRG Texas	☑		
NYSRC	☑		
Salt River Project	☑		
American Electric Power	☑		
ITC Transco	☑		

2. **The proposed standard would have requirements for the following functional entities: Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, and Load-serving Entity. Do you agree that these are the right functional entities for the proposed standard?**

Summary Consideration:

The majority of the commenters supported the functional entities for which the proposed standard would be applicable, specifically the Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, and Load-Serving Entity. All commenters that responded that they did not agree to the proposed functional entities requested clarification on the applicability to a Load-serving Entity (LSE).

The SAR Drafting Team explained that the LSE functional entity was added in response to stakeholder comments received on the first draft of the SAR. The SAR Drafting Team also explained to commenters that various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response.

One commenter suggested that if there is a future performance standard, it would be unreasonable to implement a technical standard that requires functional entities to provide data. The SAR Drafting Team does not see the linkage between requiring data from entities in order to qualify and quantify Frequency Response with the interconnections and NOT including all these entities in a Frequency Response Performance Standard.

Question #2			
Commenter	**Yes**	**No**	**Comment**
PJM		☑	The proposal as written appears to be headed towards mandating a given unit response. As such there would be an obligation on the Generator Operator - there does not seem to be any requirements that would apply to the Generator Owner - unless of course the requestor includes a requirement to install a governor (this has, to date, be an implied obligation just as having a turbine has been an implied obligation). If the requestor does intend to assert an obligation on the Generator Owner to install a governor then the question arises should that be a standard or should that be a part of the Certification of a GO? It is not clear what the LSE requirements are in this proposal.
Response: The stated purpose of this SAR is to collect and analyze data in order to determine the Frequency Response for each Interconnection, recommend a target Frequency Response for each Interconnection and determine the cause of any significant variations in Frequency Response within each of the Interconnections. In response to your comment on applicability to LSEs, various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
SWPA		☑	Load serving entities should not be included due to the characteristics of load and frequency. Load Serving Entities should contribute data to determine FRC.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR. Note that your two statements seem to contradict each other.			
NPCC CP9		☑	NPCC participating members question the need to include the applicability to the LSEs in this SAR and requests the drafting team to explain this.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
NYSRC		☑	Explain the applicability of the SAR to LSEs.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
SPP ORWG		☑	A standard can not be imposed on the response of load to frequency. Load Serving Entities can only provide data.
Response: The SAR Drafting Team agrees that the role of the LSE will primarily be to supply data concerning the composition and variations of load served within the Interconnection. There is nothing in the SAR imposing a response requirement on any of the functional entities.			
Hydro Québec TransÉnergie		☑	We question the need to include the applicability to the LSEs in this SAR and requests the drafting team to explain the purpose.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	For the purpose of data collection, assigning responsibility to the Balancing Authority, Generator Operator and Load-serving Entity would suffice.
Response: Most of the data will be collected from the entities you list. However, the SAR Drafting Team believes the other entities included in the SAR have some of the data that is needed for this standard. For example the Generator Owner might have relevant data that may not be available from the Generator Operator.			
ISO New England		☑	ISO New England does not see a need to include the applicability to the LSEs in this SAR and requests the drafting team to explain this.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
American Transmission Co.		☑	ATC does not see the need to identify the Load Serving Entity in the Applicability section. The SDT should provide an explanation as to the reasoning behind the selection of Load Serving Entities.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
Energy Mark, Inc.	☑	☑	I agree that the proposed list includes those entities that would be affected by a technical standard. However, there are many questions that must be resolved before any standard that affects the Generation Owner, Generation Operator or Load-serving Entity can be implemented. These questions relate to how a performance standard can or should be implemented. If there is no reasonable expectation that they would be included in a future performance standard, it would be unreasonable to implement a technical standard that requires these three functional entities to provide data. In a fair market that allows voluntary participation by Generation Owners, Generation Operators and Load-serving Entities, the direct application of a Frequency Response Performance Standard to these entities is not currently possible without creating unreasonable inequities in the market. Any standard applied directly to one generator but not another will create unreasonble inequities in a market. Since each generation technology has different Frequency Response capabilities, only a solution that provides Frequency Response through a market based mechanism can be fairly implimented in a market. Under these conditions, the measurement methods and data collection for a technical standard should only be applied to those entities that would have resposibilities under a

Question #2			
Commenter	**Yes**	**No**	**Comment**
			performance standard. The correct alternative for collecting data from these entities is to collect it indirectly through the Balancing Authority or Reliability Coordinator that would be directly affected by a performance standard. The inclusion of Generation Owner, Generation Operator, and Load-serving Entity directly in the data collection will lead to the development of data collection systems that will need to be replaced, if and when, a performance standard is developed. This is an inefficient way to develop the technology for a new standard.
Response: The SAR Drafting Team appreciates your input, but disagrees with some of your conclusions. The SAR Drafting team does not see the linkage between requiring data from entities in order to qualify and quantify Frequency Response with the interconnections and NOT including all these entities in a Frequency Response Performance Standard. Available Frequency Response and its distribution within an Interconnection may require that certain generators be treated differently than others due to their location and electrical characteristics. How this difference is compensated is neither within the scope of this SAR nor within NERC's authority. The SAR drafting team agrees with your statement about the data collection being performed in the most efficient manner.			
Salt River Project	☑		Ultimately there may be some impact to the Planning Coordinator and/or Resource Planner if a frequency response requirement is specified. Could there be an extreme scenario where an entity would have to consider shedding load to meet some frequency reserve criteria?
Response: The SAR Drafting Team does not anticipate that the standard resulting from this SAR will contain any requirement for specific Frequency Responses from the Interconnections or the Balancing Authorities. Future standards are beyond the scope of this SAR. The SAR Drafting Team would expect that in any standard (whether dealing with transmission, dynamics or reserves) load shedding only makes sense if the entity cannot withstand the next contingency.			
Xcel Energy Services	☑		To the extent information is needed from these entities, they are appropriate to list. It is possible that the LSE is not required.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
American Electric Power	☑		The role of the load serving entity in item 6b is unclear.
Response: Various industry experts estimate that as much as 1/3 of the total Interconnection Frequency Response may be supplied by Load Frequency Response (the other 2/3 is supplied from Turbine Governor Support). Thus information from the			

Question #2			
Commenter	Yes	No	Comment
LSE concerning the composition and variations of load served within the Interconnection can be critical in understanding total Interconnection Frequency Response. The applicability to LSEs was added at the specific request of commenters in a previous version of the SAR.			
ERCOT	☑		
CAISO	☑		
Bonneville Power Administration	☑		
KCP&L	☑		
Manitoba Hydro	☑		
MidAmerican Energy Co.	☑		
MISO	☑		
NRG Texas	☑		
NYISO	☑		
Southern	☑		
ITC Transco	☑		

3. **The SAR drafting team modified the SAR to clarify that data will be collected to model up to 5 minutes of frequency response. This should help identify the window of time where frequency response appears to be masked by AGC action. Do you agree with this clarification?**

Summary Consideration:

Most comments agreed that the clarification helped to identify the window of time when frequency response appears to be masked by AGC action. Several commenters requested more specific information on the sample rates and the specific data that would be collected. The SAR Drafting Team explained that this type of information will be developed in the standard development process and not captured in the SAR. The SAR drafting team agreed to forward these comments to the Director of Standards Development so that they can be addressed by the Frequency Response Standard Drafting Team.

Question #3			
Commenter	**Yes**	**No**	**Comment**
SWPA		☑	Need more specific information regarding sample rates. The 5-minutes of frequency response should identify time periods prior to and after the event.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
SPP ORWG		☑	The 5 minute time is adequate, but it lacks substance. Small changes in load and generation due to frequency response are very difficult to separate from normal load changes and AGC action on generation units (as was pointed out). It is important to include in the description of data collection that the 5 minutes should include 1 minute of data prior to a study event and 4 minutes after a study event. It is also important to include a sample rate, such as 4 seconds (obviously, faster samples are better, but may not be practical). The SAR, as written, lacks specifics on what data is required to perform a valid study. Some examples of necessary data may include, but are not limited to, AGC pulses, special protection systems, generator MW, tie line MW, frequency, etc.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Drafting Team. We expect the data sampling rate to			

Question #3			
Commenter	**Yes**	**No**	**Comment**
be on existing SCADA periodicity.			
Xcel Energy Services		☑	Further clarification is needed around the time period for which data will be collected. It important to note that description of the 5 minutes data collection period should include 1 minute before and 4 minutes after the event.
Response: In response to your first comment, the SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity. In response to your second comment, the SAR Drafting team agrees that data is required both before and after the contingency to be analyzed.			
ITC Transco		☑	Five minutes of data seems arbitrary. If the collection period were extended to 15 minutes, it would coincide with the Disturbance Control period.
Response: Thank you for your comment. The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
PJM		☑	As noted above PJM does not consider collecting data in order to decide what a requirement should be as grounds for a standard. Thus the sampling period which is outside of a NERC standard, can be defined in whatever way the group doing the sampling desires.
Response: Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR.			
NYSRC		☑	It is not clear what type of data is going to be collected from this requirement. AGC response is continuous. What is the justification for the specific "five minutes" reffered to? Since AGC control is every 4 seconds, five minutes appears to be too long a period to collect this data. Imposing this requirement will require the installation of local data storage retention facilities & telemetering equipment that may not be necessary.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were			

Question #3			
Commenter	**Yes**	**No**	**Comment**
withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
NPCC CP9		☑	It is not clear what type of data is going to be collected from this requirement. AGC response is continuous. What is the justification for the specific "five minutes" referred to? Since AGC control is every 4 seconds, five minutes appears to be too long a period to collect this data. Imposing this requirement will require the installation of local data storage retention facilities & telemetering equipment that may not be necessary and NPCC participating members would like the drafting team to explain why 5 minutes is necessary. Also, when requesting data from a generator what is expected scan-rate/exception reporting clarity of the data?
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
KCP&L		☑	The 5 minute time is adequate, but it lacks substance. Small changes in load and generation due to frequency response are very difficult to separate from normal load changes and AGC action on generation units (as was pointed out). It is important to include in the description of data collection that the 5 minutes should include 1 minute of data prior to a study event and 4 minutes after a study event. It is also important to include a sample rate, such as 4 seconds (obviously, faster samples are better, but may not be practical).
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
Energy Mark, Inc.	☑	☑	I agree with the concept of measuring Frequency Response for an extended period after a disturbance, but I do not agree that the reason is related to masking by AGC action. If the Frequency Bias for a Balancing Authority is set to a value that approximates the actual Frequency Response, the AGC action will always provide the correct response for

Question #3			
Commenter	**Yes**	**No**	**Comment**
			reliable interconnection performance. The Frequency Response should be measured for an extended period after a disturbance to identify entities that are prematurely withdrawing their expected frequency response support from the interconnection. This has been demonstrated for entities that have outer loop control that only includes scheduled deliveries without adjustment for frequency response.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
Hydro Québec TransÉnergie	☑	☑	We requests clarification as to what data and at what periodicity will be collected from the identified entities.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
ISO New England	☑	☑	ISO New England requests clarification as to what data and at what periodicity will be collected.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
MISO	☑	☑	Five minutes is acceptable. There may be merit in collecting 15 minutes of data to cover the DCS window. The data should be readily available since the BAs are already examining this data to determine their compliance with the DCS standard. The final decision can be made during the standards drafting phase.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data			

Question #3			
Commenter	**Yes**	**No**	**Comment**
sampling rate to be on existing SCADA periodicity.			
NYISO	☑	☑	It is not clear what type of data is going to be collected from this requirement. AGC response is continuous. What is the justification for the specific "five minutes" reffered to? Since AGC control is every 4 seconds, five minutes appears to be too long a period to collect this data. Imposing this requirement will require the installation of local data storage retention facilities & telemetering equipment that may not be necessary and NPCC participating members would like the drafting team to explain why 5 minutes is necessary. Also, when requesting data from a generator what is expected scan-rate/exception reporting clarity of the data?
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
ERCOT	☑		This time frame should be sufficient for determination of frequency response. If it is intended that this data should also be useful for evaluating generating unit governor functioning, a longer time may be appropriate.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not captured in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
Manitoba Hydro	☑		Ten minutes might be more useful, especially in any areas where it appears to take a long time to settle down after a frequency deviation event. This could be left up to the discretion of operators and balancing authorities in any areas where slow or bumpy returns to normal frequency levels are experienced.
Response: The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not in the SAR. The five minute period was proposed based on comments to a prior version of the SAR. Some commenters were concerned that governors were withdrawing response shortly after the initial excursion. The SAR drafting team will forward these comments to the Director of Standards Development so that they can be addressed by the Frequency Response Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
Salt River Project	☑		
Southern	☑		
NRG Texas	☑		
MidAmerican Energy Co.	☑		
IESO	☑		
Bonneville Power Administration	☑		
CAISO	☑		
American Electric Power	☑		

4. Should a field trial be initiated, whereby a set of events for each Interconnection is posted throughout the year, to be used by BAs to calculate their 2007 Frequency Response?

Summary Consideration:

Most commenters indicated that a field trial should be initiated whereby a set of events for each Interconnection is posted throughout the year, to be used by Bias to calculate their 2007 Frequency Response.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro			Only if field trials are deemed to have very high probability of not causing significant difficulties on overly sensitive network area.
Response: The SAR Drafting Team agrees that no field trial should adversely impact the reliability of the Bulk Power System.			
MidAmerican Energy Co.		☑	This is not a new concept. I support institution of the standard as written so a start can be made to identify and, with luck, remediate the decline in frequency response.
Response: Thank you for your support.			
Bonneville Power Administration		☑	BPA does not believe a field trial is needed for this standard. The standard should be written and implemented with the levels of noncompliance structured around data submittal.
Response: Thank you for your support.			
PJM		☑	There are field trials for standards (which this question is directed) and there are field trials for good ideas. This proposed SAR would seem to fall into the second category; and while posting events is interesting, it does not rate being a NERC standard. Collecting and posting data can be effected without a standard.
Response: Thank you for your comment.			
NYSRC		☑	
Energy Mark, Inc.	☑	☑	This would be a good way to insure that every entity select a similar set of events for calculation of their Frequency Response, but it will not insure conformity of the results. The difficulty with any method for selecting a common set of events is that each of those events is caused by a disturbance within one or more of the Balancing Authorities on the interconnection. Those entities that cause the disturbance will experience a different frequency response than those entities that are responding. The net effect is that the sum of the responses for all of the entities on the interconnection must sum to zero. This means that each entity must eliminate those disturbances for which they are the cause, from the set of disturbances they use to estimate their response. The real advantage is an entity cannot influence the results of the measurement through selection of the events they choose to include in the calculation.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response: Thank you for your comment. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team.			
MISO	☑		This should not be a problem as BAs should already be performing this calculation in the annual determination of their frequency bias.
Response: Thank you for your comment.			
NRG Texas	☑		A field trial may indicate the need for more or different data for the proper calculation of a BAs Frequency Response.
Response: Thank you for your comment.			
ERCOT	☑		A field trial would be beneficial to ensure that no gaps in the need for data exist. This could relate to whether other data is needed or whether data for a longer time is needed.
Response: Thank you for your comment.			
IESO	☑		A field test is a must and would definitely provide useful information on the types of event that would necessiate such data collection (The threshold needs to be clarified though - e.g. should it be >10MW loss of generator or some other threshold?), and any specific areas that need to be worked on in order to ensure that all relevant and required data is collected.
Response: Thank you for your comment. The SAR Drafting Team agrees with the comment. Specific information, such as sampling rate and specific data requirements, will be developed in the standard development process and not in the SAR. The SAR drafting team will forward these comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team. We expect the data sampling rate to be on existing SCADA periodicity.			
Southern	☑		Currently BAs in the Eastern Interconnection have little, if any, way to actually calculate their frequency responses. As a result, most default to the one percent minimum. A good database of disturbance events will provide the information to calculate BA frequency response more accurately while at the same time allowing the NERC OC/RS to determine if the one percent minimum is appropriate in the EI today.
Response: Thank you for your comment.			
Hydro Québec TransÉnergie	☑		
CAISO	☑		
ISO New England	☑		
KCP&L	☑		
NPCC CP9	☑		

Question #4			
Commenter	**Yes**	**No**	**Comment**
NYISO	☑		
SPP ORWG	☑		
Salt River Project	☑		
Xcel Energy Services	☑		
American Electric Power	☑		
ITC Transco	☑		
SWPA	☑		

5. **Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.**

Question #5	
Commenter	**Comment**
Bonneville Power Administration	BPA agrees with the necessity of a frequency response standard. BPA highly encourages that this effort be implemented as soon as possible.
Response: Thank you for your support.	
Constellation	Specific to the Requirement 6 a which states: Each Generator Operator that operates a generator larger than [10 MW]*, shall provide data to its Balancing Authority, as required in item 6, to support this standard and for use in developing models of Frequency Response in the associated Interconnection. Balancing Authorities may seek Speed Droop characteristics for our generators. Speed Droop is a design characteristic of the steam turbine (or the prime mover's governor response in the case of a combustion turbine or diesel) . Our concern is the only data we may be able to provide would be turbine manufacturer design data. For our older units where turbine control systems have been retrofitted and upgraded with more modern controls, we may not really know the speed droop characteristic of the unit. Collecting performance data to demonstrate the speed droop is extremely difficult if not impossible on a large unit. (Requires the grid connection frequency be allowed to "droop" as the generator is loaded). Hence, as now written, Constellation Generation is not clear how we could comply.
Response: The SAR Drafting Team anticipates that Frequency Response information will be collected directly from measured quantities on the grid or the generator bus. We do not anticipate using design curves or other archival data.	
Energy Mark, Inc.	One of my concerns is a majority of entities in NERC must agree that there is a need for a standard before the standard process moves forward. This could have undesirable long-term results with respect to the quality of the standards that are developed. This standard provides a good example of this problem. From what I have observed, both the Texas and Western Interconnections have concluded that there is a reliability need for a Frequency Response Standard on their interconnections. Unfortunately, reasonable opposition from the Eastern Interconnection will prevent the development of a common standard for those two interconnections. The only alternative will be for the Texas and Western Interconnections to each develop their own standards for Frequency Response without considering ways of making those two standards similar to each other. If the Eastern Interconnection, after a few years, finds that it needs a Frequency Response Standard, it will then become necessary for a new standard to be developed that applies to all three interconnections.

Question #5	
Commenter	**Comment**
	If each interconnection has a different Frequency Response Standard, it means there is no standard at all, but three different rules for NERC. The next logical step is to develop a common standard for all three interconnections requiring the first two standards developed by the Texas and Western Interconnections separately be modified to conform to a North American Standard on Frequency Response. Combining these three separate needs into a single standard will result in a natural opposition to change by those interconnections that have already implemented an interconnection standard that meets their individual needs. This will make it very difficult to gain the support necessary to enact a common standard for NERC. This multi-step development can only be avoided by having all three interconnections participate and contribute to standards identified and developed by individual interconnections. I believe that NERC needs to find a way to address this problem. If they do not, the standard development and approval process will lead to fractured standards and an unacceptable fractured standard process for NERC. One alternative might be to find a way for all interconnections to participate in the solution of individual interconnection problems as part of the standard development process.
Response: Thank you for your comment. We believe the Standards Development Procedure provides the solution you are seeking. The proposed SAR sets the foundation for a technical standard for a common way to measure and evaluate frequency response. Should a Region or Interconnection determine they need a more stringent, performance-based standard, there is a means to pursue a difference.	
Hydro Québec TransÉnergie	Being a single Balancing Authority Interconnection, there might be a need for a «regional» difference for the Québec Interconnection when specific value will be established. Same as ERCOT, frequency response will be based on the change in generation (or load) rather than Tie-Line deviation.
Response: We agree with this comment. The SAR Drafting Team anticipates that specific regional differences will be addressed in the Standard and not in the SAR.	
IESO	While we felt that the previous SAR was unclear on the intent, this SAR has such a reduced scope that the intended task does not require a reliability standard to achieve . A task team charged by a standing committee (the OC), would suffice. The requirements proposed in the SAR can be set as conditions for completing the data collection effort by the task team.
Response: The SAR Drafting Team disagrees and believes that the scale of this project, the ongoing nature, and the potential importance of the conclusions to be developed per the specifications in Paragraphs 5 and 6 are sufficiently important to warrant the use of the NERC Reliability Standards Process.	
KCP&L	The reasoning for this technical standard is based on the perception that the frequency response of the electrical system is declining and a concern that the interconnect's ability to arrest significant system disturbances is slowly being compromised. Although it is not disagreeable that a study be conducted to determine if an actual decline in frequency response is occuring and then to determine cause, it is diagreeable to propose a potential remedy for a problem that may not exist or, dependent on the findings, in inappropriate remedy.

Question #5	
Commenter	**Comment**
	One reason a decline in frequency response may be perceived occuring is a result of more on-line generating units being fully loaded. That means when a frequency decline occurs there are less units able to respond because they are already loaded. That does not mean the interconnection is at risk. As long as Balancing Authorities are maintaining their reserve obligations, even large contingencies should be manageable. However, over the years because of the trend to get more out of invested generation resources, it would give the appearance of a decline in frequency response since most frequency degradations are a result of losses of generation and a resultant decline in system frequency and those are what is studied and scrutinized. The August 14, 2003 disturbance was an opportunity to study the frequency response of all on-line generating units due to the frequency event resulting in a high frequency. High frequency is the only event where all on-line generating units will respond. Proposing the establishment of a Target Frequency Response for the interconnect before concluding if an actual decline in frequency response is occuring and the subsequent cause(s) for the decline is finding a solution before defining the problem. Any standards involving frequency response needs to also consider the role system reserves play in the interconnect as well as the frequency response of generators and system load to frequency. As long as generating reserve obligations are being met to meet current Reliability Standards and Regional Operating Criteria there may not be a need to go further dependent on the outcome of the study proposed by this SAR.
Response: The SAR Drafting Team agrees with you speculations, but strongly believes that actual field data must be collected and analyzed to determine the specific processes impacting Frequency Response. It may well be that no further action will be required, but that is beyond the scope of this SAR.	
MidAmerican Energy Co.	I have concern about the "shall"s in the standard, in that there is no apparent enforcement behind the requirements for data submittals. If I'm wrong in this, then I would be comfortable with the effectiveness possible. If I'm right, what is to be done with an entity which finds it convenient not to report?
Response: The SAR Drafting Team anticipates that the Standard that evolves from this SAR will have measures for such things as failure to report and other practical details.	
NRG Texas	Frequency Response of Resources is vital to the reliability of an interconnection. Large differences between the measured Frequency Response of a BA, its Bias setting and the models of Frequency Response may indicate a reliability risk. Updating the models with accurate Frequency Response data will improve the evaluation of this reliability risk. Please implement this process as soon as possible.
Response: The SAR Drafting Team agrees and thanks you for your support.	
NYSRC	The results of the data collection efforts should be used to develop a standard governing frequency response.

Question #5	
Commenter	**Comment**
Response: The SAR Drafting Team agrees and thanks you for your support.	
Southern	This SAR starts the process toward understanding frequency behavior, particularly in the Eastern Interconnection. In our opinion this is a necessary first step in determining whether we need frequency response allocations or other measures to ensure the sustained frequency performance that is required for reliable operations. Wherever possible, the scope and extent of data collection required for generators, their dynamic models including all associated control devices, and any other system data parameters covered under this SAR be limited such that it should not duplicate or exceed system modeling data requirements of any other NERC standard. One important system modeling parameter not emphasized in this SAR is the characteristic behavior of load at each substation (constant power, constant current, etc.), which would seem to have a significant effect on overall frequency response of the interconnected system. It is quite possible that advancements in consumer appliances and electronics, and their proliferation of use, have collectively changed the overall characteristics of system load to a composite state that is significantly different from modeling assumptions made within the previous few years.
Response: The SAR Drafting Team agrees and thanks you for your support.	
SPP ORWG	The reasoning for this technical standard is based on the perception that the frequency response of the electrical system is declining and a concern that the interconnect's ability to arrest significant system disturbances is slowly being compromised. Although it is not disagreeable that a study be conducted to determine if an actual decline in frequency response is occuring and then to determine cause, it is diagreeable to propose a potential remedy for a problem that may not exist or, dependent on the findings, in inappropriate remedy. Types of generating units online (e.g., wind generation, combined cycle, etc) and their subsequent loading will have an influence on the frequency response of the system. As long as Balancing Authorities are maintaining their reserve obligations, even large contingencies should be manageable. However, over the years because of the trend to get more out of invested generation resources, it would give the appearance of a decline in frequency response since most frequency degradations are a result of losses of generation and a resultant decline in system frequency and those are what is studied and scrutinized. The August 14, 2003 disturbance was an opportunity to study the frequency response of all on-line generating units due to the frequency event resulting in a high frequency. High frequency is the only event where all on-line generating units will respond. Proposing the establishment of a Target Frequency Response for the interconnect before concluding if an actual decline in frequency response is occuring and the cause(s) for the decline is finding a solution before defining the problem. Any standards involving frequency response need to also

<table>
<tr><th colspan="2">Question #5</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>consider the role system reserves play in the interconnect as well as the frequency response of generators and system load to frequency. As long as generating reserve obligations are being met in accordance with current Reliability Standards and Regional Operating Criteria there may not be a need to go further dependent on the outcome of the study proposed by this SAR.</td></tr>
<tr><td colspan="2">Response: The SAR Drafting Team disagrees and believes that a fundamental understanding of frequency response in each of the Interconnections is necessary to ensure reliability of the Bulk Power System. This is particularly important as new, untested technologies are integrated into the Bulk Power System with potentially unanticipated outcomes. Although no follow up Standards may be required after the Frequency Response Standard is developed, there is a potential risk to Interconnection reliability unless we do implement this SAR and Standard and develop a firm understanding of specifically how Frequency Response operates.

It appears that there is a misunderstanding of the Target Frequency Response in that this does not set a minimum for any particular Balancing Authority. The Target Frequency Response sets a benchmark, beyond which additional data is needed from the Balancing Authority.</td></tr>
<tr><td>Salt River Project</td><td>The SAR includes some requirement language pertaining to generators greater than 10 MW. Old NERC Policy included language requiring frequency responsive governors "unless restricted by regulatory mandates". This makes sense for most nuclear facilities. Another type of restriction on governors involves small hydro units that are dependent on water order. For this type of unit there truly is no governor response yet the unit capabilities may exceed 10 MWs. Please consider these types of exemptions as work progresses on this SAR and resulting standard.</td></tr>
<tr><td colspan="2">Response: Your comments are good and will be provided to the Standard Drafting Team as it wrestles with the specific details of this project. The SAR does not propose to set a mandatory level of governor response for each generator. The proposed standard requires data and an identification of which generators are not providing response should the Balancing Authority be below the Target Response.</td></tr>
<tr><td>Xcel Energy Services</td><td>Establishing a Target Frequency Response is premature. It advances a proposed remedy in advance of first meeting the intent of the SAR-determining the cause for the percieved decline in frequency response. It is our view that the percieved decline of frequency response, if that turns out to be the confirmed as a true decline, of itself does not necessarily indicate an significantly increased threat to reliability. As long as generating reserve obligations are being met to meet Reliability Standards and the real time regulating reserves are being carried, also to meet Standards, there may not be a need to go further depending on the outcome of the study proposed by the SAR.</td></tr>
<tr><td colspan="2">Response: The SAR Drafting Team does not anticipate that a Target Frequency Response will be developed until such time that it can be technically supported as required by the NERC Reliability Standards Process.</td></tr>
<tr><td>PJM</td><td>PJM would also note that the proposal references two distinct parameters - the Natural response of a BA; and the natural response of a unit. It is not clear how the requestor intends to link the two parameters. The sum of the units' natural responses will not equal the natural response of the BA.</td></tr>
</table>

Question #5	
Commenter	**Comment**
	Does the requestor intend to link the two, or to keep them separate? As written it appears that the requestor intends for the BA to be held responsible for an annual measured value. The SAR DT does not recognize that during different times there are different number of units opperating and available to respond. The SAR DT makes no mention of whether or not a BA(?) would have to shed load to maintain such frequency response (for those periods when all units are at full load). The SAR DT makes no mention of distance from an event. An event in NE will effect more response in NE then in Florida - how will that be addressed? PJM would ask for clarification on what the requestor would intend to mandate. FERC has recognized the need to include suppliers that use load control - how does this SAR intend to address such 'natural response suppliers'? As written this proposal becomes an ambiguous standard as it obligates a BA to get data from a generator (as opposed to directly obligating generators to supply the data to the analysis team - this is important from the perspective of who would be non-compliant if the data were not supplied - the BA or the GO?). PJM would suggest that NERC create a Frequency Project, budget the project through its members rather then create a standard and risk imposing non-compliance penalities for what potentially could be a non-issue. Deal with this for what it is - a research activity.
Response: The SAR Drafting Team appreciates your thoughtful comments but does not agree with your conclusions. Many of the details you are concerned about will be worked out as part of the details addressed by the Standards Drafting Team. The SAR Drafting Team does not anticipate that this SAR will mandate any specific frequency response. The stated purpose of this SAR is to collect and analyze data in order to determine the Frequency Response for each Interconnection, recommend a target Frequency Response for each Interconnection and determine the cause of any significant variations in Frequency Response within each of the Interconnections. In response to your suggestion to create a Frequency Project, the NERC Standards Development Procedure Manual allows for the development of SAR/Standard to collect and analyze data as needed to ensure the reliability of Interconnections.	
SWPA	Data collection and FRC assessments should also take into account loss of load, not just loss of generation. If load is lost, causing a high frequency excursion, FRC should be observed on heavily loaded generators.
Response: You are correct; however the collection of statistically significant load loss data has proven to be very difficult, if not impossible, in the past. The SAR Drafting Team will forward your comments to the Director of Standards so that they can be addressed by the Frequency Response Standard Drafting Team.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

BAL-003-1 – Frequency Response and Frequency Bias Setting
Project 2007-12 - 1st Draft

There are a few places where the team missed providing a comment in response to a suggestion – these are highlighted in yellow. In general, the team did a good job of responding!

The Frequency Response and Frequency Bias Setting Drafting Team thanks all commenters who submitted comments on the 1st draft of BAL-003-1 – Frequency Response and Frequency Bias Setting. This standard was posted for a 30-day public comment period from February 4, 2011 through March 7, 2011. The stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 36 sets of comments, including comments from more than 139 different people from approximately 86 companies representing 10 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received the drafting team made the following changes to the proposed Standard:

- Removed the Single Event Frequency Response Data (SEFRD) definition from the standard.
- Modified the definitions for Frequency Response Measure (FRM) and Frequency Response Obligation (FRO).
- Modified the proposed definition of Frequency Bias Setting.
- Modified FRS Form 1 to correct errors, allow for adjustments and provide clarity.
- Separated Attachment A Background Document into two documents; 1) Attachment A – Supporting Document detailing the methodology to be followed for calculations, and 2) Background Document detailing the rational for the development of the requirements.
- Created Attachment B – Process for Adjusting Bias Setting Floor to clarify the methodology to be used in reducing the present 1% minimum Frequency Bias Setting.
- Added measures, VRFs and VSLs.

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

- A few stakeholders requested the SDT to consider a standard for generators to support the Balancing Authority in achieving the targeted level of Frequency Response. The team stated that this was outside the scope of the industry approved SAR. The SDT further stated that any entity could submit a SAR addressing this issue to the SC for consideration and that the SDT supported this option.

- A couple of comments stated they believed that the standard should support the development of a market for supporting a Balancing Authority in achieving the target Frequency Response. The SDT explained that this standard would provide for the metrics for Frequency Response while the market would define itself. The SDT further stated a market could be created by a region, sub-region, ISO, RTO or other entity as appropriate to facilitate compliance however the NERC Reliability Standards do not establish markets.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received can be viewed in their original format at:

http://www.nerc.com/filez/standards/Frequency_Response.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Index to Questions, Comments, and Responses

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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Bohdan M. Dackow	US Power Generating Company (USPG)	NPCC	NA
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5

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

11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chantel Haswell	FPL Group, Inc.	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
2.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. Tom Abrams	Santee Cooper	SERC	1
2.	Glenn Stephens	Santee Cooper	SERC	1
3.	Rene Free	Santee Cooper	SERC	1
4.	Wayne Ahl	Santee Cooper	SERC	1
5.	Jim Peterson	Santee Cooper	SERC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6

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

9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Brent Ingebrigtson	LG&E and KU Energy			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	NA - Not Applicable	1
2.	Annette Bannon	PPL Generation LLC	NA - Not Applicable	5
3.	Mark Heimbach	PPL Energy Plus	NA - Not Applicable	6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Jason Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3
2.	Terry Harbour	Midamerican Energy	MRO	1
3.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6
4.	Mike Moltane	ITC Holdings	RFC	1

				1	2	3	4	5	6	7	8	9	10
6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jamie Murphy	BPA, Transmission Technical Operations	WECC	1
2.	Bart McManus	BPA, Transmission Technical Operations	WECC	1
3.	Dave Kirsch	BPA, Transmission Technical Operations	WECC	1
4.	Deanna Phillips	BPA, FERC Compliance Office	WECC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Development										

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield, MO	SPP	1, 4

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

2.	Michelle Corley	Cleco	SPP	1, 3, 5
3.	Lisa Duffey	Cleco	SPP	1, 3, 5
4.	Jeff Elting	Nebraska Public Power District	MRO	1, 3, 5
5.	Denney Fales	Kansas City Power & Light	SPP	1, 3, 5, 6
6.	Louis Guidry	Cleco	SPP	1, 3, 5
7.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
8.	Rick Koch	Nebraska Public Power District	MRO	1, 3, 5
9.	Errol Ortego	Louisiana Energy and Power Authority	SPP	10
10.	David Pham	Empire District Electric	SPP	1, 3, 5, 6
11.	Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
12.	John Stephens	City Utililties of Springfield, MO	SPP	1, 4
13.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
14.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
15.	Barry Warren	Empire District Electric	SPP	1
16.	Bryn Wilson	Empire District Electric	SPP	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Albert DiCaprio	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Matt Goldberg	ISO-NE	NPCC	2
3.	Dan Rochester	IESO	NPCC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Mark Thompson	AESO	WECC	2
6.	Greg Van Pelt	CAISO	WECC	2
7.	Charles Yeung	SPP	SPP	2
8.	Terry Bilke	Midwest ISO	RFC	2
9.	Greg Campoli	NYISO	NPCC	2
10.	Kathleen Goodman	ISO-NE	NPCC	2
11.	Ben Li	IESO	NPCC	2
12.	Jason Marshall	Midwest ISO	RFC	2
13.	Don Weaver	NBSO	NPCC	2

				1	2	3	4	5	6	7	8	9	10
10.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Neagle	AECI	SERC	1, 3, 5
2.	Larry Akens	TVA	SERC	1, 3, 5, 9
3.	Chris Adams	EKPC	SERC	3, 5, 9, 1
4.	Joel Wise	TVA	SERC	1, 3, 5, 9
5.	Ron Wyble	CWLD	SERC	1, 5, 9
6.	Andy Burch	EEI	SERC	1, 5
7.	Rene' Free	Santee Cooper	SERC	1, 3, 5, 9
8.	Glenn Stephens	Santee Cooper	SERC	1, 3, 5, 9
9.	Robert Thomasson	BREC	SERC	1, 3, 5, 9
10.	Gene Delk	SCE&G	SERC	1, 3, 5
11.	Mike Oatts	Southern	SERC	1, 3, 5
12.	Sam Holeman	Duke	SERC	1, 3, 5
13.	Marc Butts	Southern	SERC	1, 3, 5
14.	Melinda Montgomery	Entergy	SERC	1, 3
15.	Ron Carlsen	Southern	SERC	1, 3, 5
16.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
17.	John Troha	SERC	SERC	10

				1	2	3	4	5	6	7	8	9	10
11.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jennifer Flandermeyer	Kansas City Power & Light	SPP	1, 3, 5, 6
2.	Denney Fales	Kansas City Power & Light	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
12.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
13.	Individual	Cindy Martin	Southern Company	X		X							
14.	Individual	James Eckelkamp	Progress Energy	X		X		X	X				
15.	Individual	Rob Coulbeck	ENBALA Power Networks										
16.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
17.	Individual	John Canavan	NorthWestern Energy	X									
18.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
19.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Isaac Read	Beacon Power Corporation						X				
21.	Individual	Bryan Taggart	Westar Energy	X		X		X	X				
22.	Individual	Thomas Washburn	FMPP						X				
23.	Individual	Chris Adams	EKPC	X				X		X	X		
24.	Individual	Kathleen Goodman	ISO New Engand Inc.		X								
25.	Individual	Hao Li	Seattle City Light	X		X	X	X	X				
26.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
27.	Individual	JC Culberson	ERCOT		X								
28.	Individual	Howard Rulf	We Energies			X	X	X					
29.	Individual	Thad Ness	American Electric Power	X		X		X	X				
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	LeRoy Patterson	Patterson Consulting, Inc.										
32.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
33.	Individual	Todd Bennett	Associated Electric Cooperative, Inc.	X		X		X	X		X		
34.	Individual	Mark Thompson	Alberta Electric System Operator		X								
35.	Individual	Dan Rochester	Independent Electricity System Operator		X								
36.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

1. The SDT has developed three new terms to be used with this standard.

- ***Single Event Frequency Response Data (SEFRD) The individual sample of event data from a Balancing Authority which represents the change in Net Actual Interchange (NIA), divided by the change in frequency, expressed in MW/0.1Hz.***
- ***Frequency Response Measure (FRM) The median of all Single Event Frequency Response Data observations reported annually on FRS Form 1.***
- ***Frequency Response Obligation (FRO) The Balancing Authority's contribution to the total aggregate Frequency Response needed for reliable operation of an Interconnection assigned by the ERO.***

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

Summary Consideration: The majority of the commenters disagreed with the proposed definitions for this standard. The primary concerns cited are the definitions, and the calculations and methodology associated with the definitions, are not clear.

Many commenters expressed concern that the FRM methodology did not allow exclusion of events that, if included, would mask true frequency response. Commenters also indicated that the 'average' and not the 'median' should be used for the FRM calculation. Other observations include inconsistency between the FRM definition and its calculation on FRS Form 1; that proposed language allows the ERO to unilaterally change FRO value; and that definitions seem more focused on the frequency excursion curve point B value and not point C value. Suggestions for improving the standard include making it clear that 25 events are used for determining FRM; that definitions should specify how to calculate each term; and that FRM should take into account nonconforming load.

In response to industry comments, the SDT has deleted the SEFRD definition from the standard; revised the FRO and FRM definitions; and also improved the calculations. With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. FRS Form 1 has been modified to allow for adjustments to the load and generation. To allay industry concern over the ERO's role, the SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks specified in the standard is necessary.

In regards to concerns over the frequency excursion curve point B value, the SDT explained that while point B measurements have some data quality challenges to be mastered, point C measurements are not practical at this time for Balancing Authorities in an Interconnection with more than one Balancing Authority. The SDT intends to study point B and point C relationships of each Interconnection with more than one Balancing Authority to address this issue during the field trial.

The SDT has chosen the deterministic approach detailed in Attachment A as the method to use to allocate the Interconnection FRO to the BAs. The SDT is evaluating a probabilistic method during the field trial.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Patterson Consulting, Inc.	No	From the definition, it is not clear whether SEFRD is a Balancing Authority's 1) data collected for each frequency event, 2) calculated Frequency Response for a selected event, 3) Net Actual Interchange divided by the change in frequency for a selected event, or 4) some combination of these interpretations. If the SDT determines that adjustments to Net Actual Interchange should be made such as adjustments for joint-owned generation and nonconforming loads as suggested in the field test document, then since this definition requires Frequency Response to be determined from Net Actual Interchange, this definition would require changing to allow those adjustments. I suggest defining SEFRD as "The individual sample of event data from a Balancing Authority that is necessary to calculate its Frequency Response on FRS Form 1, expressed in MW/0.1Hz." FRM: This definition and its calculation in FRS Form 1 do not match. FRS Form 1 calculates FRM as "The median of Single Event Frequency Response Data observations reported annually on FRS Form 1 [for events external to the Balancing Authority]." (Brackets added for emphasis.) The FRS Form 1 calculation appears more appropriate based on data collected, since data are not reported and calculations are not adjusted to compensate for contingencies within the Balancing Authority. Regardless, the difference between definition and calculation makes it impossible for a Balancing Authority to know the expected performance measure. FRO: The definition should be changed to remove the opposing concepts of performance and obligation. For example: FRO is defined to be "The Balancing Authority's contribution to the total aggregate Frequency Response…" FRM, not FRO, is the Balancing Authority's contribution toward the aggregated Frequency Response. FRO is "The Balancing Authority's allocation of the interconnection's required Frequency Response…" or "The Balancing Authority's required Frequency Response needed for reliable operation of an Interconnection …"
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT has modified the definition for FRM to read "The median of all the Frequency Response observations reported annually on FRS Form 1." The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection."		
Santee Cooper	No	We suggest the SDT consider defining SEFRD as: The calculated frequency response by a Balancing Authority for a specific frequency excursion event as identified by the ERO (or NERC). As a comment, how frequency response is calculated needs to be defined and may not always be the Net Actual Interchange (NIa) divided by the change in frequency expressed in hertz. For example, the NIa may need to be adjusted for known generation and load changes that do not represent frequency response for the period being measured such as known generation and load ramp changes. Change in frequency needs to be more specific, such as the frequency difference between B and A measured at B. If Frequency Response Obligation (FRO) is a targeted value, then perhaps the definition should be: The

Organization	Yes or No	Question 1 Comment
		Balancing Authority’s annual median frequency response as assigned by the ERO (or NERC). The word “contribution” should be considered to be replaced with “the balancing authority piece of the total.....”The review team is concerned that the FRO and FRM definitions do not contain enough clarity as to how the BAs will be held accountable. Also, the definitions do not explain who will determine the value of each BA’s FRO and the method used to determine the FRO value.Should the definition of Frequency Response Measure be a median or mean value?
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read “The Balancing Authority’s share of the required Frequency Response needed for the reliable operation of an Interconnection.” With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		
LG&E and KU Energy	No	We suggest the SDT consider defining SEFRD as: The calculated frequency response by a Balancing Authority for a specific frequency excursion event as identified by the ERO (or NERC). As a comment, how frequency response is calculated needs to be defined and may not always be the Net Actual Interchange (NIa) divided by the change in frequency expressed in hertz. For example, the NIa may need to be adjusted for known generation and load changes that do not represent frequency response for the period being measured such as known generation and load ramp changes. Change in frequency needs to be more specific, such as the frequency difference between two physical locations B and A measured at B. Frequency deviation used in the calculation needs to be the deviation observed by the BA performing the calculation. If Frequency Response Obligation (FRO) is a targeted value, then perhaps the definition should be: The Balancing Authority’s annual median frequency response as assigned by the ERO (or NERC). The word “contribution” should be considered to be replaced with “the balancing authority piece of the total.....”The standard does not explain who will determine the value of each BA’s FRO nor the method used to determine the FRO value. Should the definition of Frequency Response Measure be a median or mean value?
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read “The Balancing Authority’s share of the required Frequency Response needed for the reliable operation of an Interconnection.” With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		

Organization	Yes or No	Question 1 Comment
SERC OC Standards Review Group	No	We suggest the SDT consider defining SEFRD as: The calculated frequency response by a Balancing Authority for a specific frequency excursion event as identified by the ERO (or NERC). As a comment, how frequency response is calculated needs to be defined and may not always be the Net Actual Interchange (NIa) divided by the change in frequency expressed in hertz. For example, the NIa may need to be adjusted for known generation and load changes that do not represent frequency response for the period being measured such as known generation and load ramp changes. Change in frequency needs to be more specific, such as the frequency difference between B and A measured at B. If Frequency Response Obligation (FRO) is a targeted value, then perhaps the definition should be: The Balancing Authority's annual median frequency response as assigned by the ERO (or NERC). The word "contribution" should be considered to be replaced with "the balancing authority piece of the total....."The review team is concerned that the FRO and FRM definitions do not contain enough clarity as to how the BAs will be held accountable. Also, the definitions do not explain who will determine the value of each BA's FRO and the method used to determine the FRO value. Should the definition of Frequency Response Measure be a median or mean value?
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." The ERO is the responsible party for determining a BA's FRO. The explanation of who determines the BA's FRO as-well-as how the BA's FRO is determined is now contained in the revised Attachment A. With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		
South Carolina Electric and Gas	No	We suggest the SDT consider defining SEFRD as: The calculated frequency response by a Balancing Authority for a specific frequency excursion event as identified by the ERO (or NERC). As a comment, how frequency response is calculated needs to be defined and may not always be the Net Actual Interchange (NIa) divided by the change in frequency expressed in hertz. For example, the NIa may need to be adjusted for known generation and load changes that do not represent frequency response for the period being measured such as known generation and load ramp changes. Change in frequency needs to be more specific, such as the frequency difference between B and A measured at B. If Frequency Response Obligation (FRO) is a targeted value, then perhaps the definition should be: The Balancing Authority's annual median frequency response as assigned by the ERO (or NERC). The word

Organization	Yes or No	Question 1 Comment
		"contribution" should be considered to be replaced with "the balancing authority piece of the total....." The review team is concerned that the FRO and FRM definitions do not contain enough clarity as to how the BAs will be held accountable. Also, the definitions do not explain who will determine the value of each BA's FRO and the method used to determine the FRO value. Should the definition of Frequency Response Measure be a median or mean value? May need to clarify what FRS stands for.
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." The ERO is the responsible party for determining a BA's FRO. The explanation of who determines the BA's FRO as-well-as how the BA's FRO is determined is now contained in the revised Attachment A. With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		
MRO's NERC Standards Review Subcommittee	No	For Frequency Response Measure, the drafting team should consider using average rather than median. Because median is literally the middle value, a Balancing Authority could have 12 really bad Single Event Frequency Response Data and still comply. Average values would prevent this from happening. Should FRM be clear that it includes at least 25 events in the definition? While that can be garnered from Attachment A, it is not specified in the Form 1 instructions. We are concerned that the regulators may argue that 25 events do not apply because an attachment is not part of the standard.
Response: Based on analysis of data the SDT has determined that the median value is the proper method to be used in defining FRM. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that Requirement.		
Midwest ISO Standards Collaborators	No	For Frequency Response Measure, the drafting team should consider using average rather than median. Because median is literally the middle value, a Balancing Authority could have 12 really bad Single Event Frequency Response Data and still comply. Average values would prevent this from happening. Should FRM be clear that it includes at least 25 events in the definition? While that can be garnered from Attachment A, it is not specified in the Form 1 instructions. We are concerned that the regulators may argue

Organization	Yes or No	Question 1 Comment
		that 25 events do not apply because an attachment is not part of the standard.
Response: With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that Requirement.		
We Energies	No	For Frequency Response Measure, the drafting team should consider using average rather than median. Because median is literally the middle value, a Balancing Authority could have 12 really bad Single Event Frequency Response Data points and still comply. Average values would prevent this from happening.Should FRM be clear that it includes at least 25 events in the definition? While that can be garnered from Attachment A, it is not specified in the Form 1 instructions. We are concerned that the regulators may argue that 25 events do not apply because an attachment is not part of the standard.
Response: With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that Requirement.		
Westar Energy	No	For FRM, why is median used rather than average? The method in the standard for dsetermining FRM needs to allow for excluding some events due to non-conforming loads, scan rates, intermittent resources, large interchange ramps, etc that may cause the actual response during the 16 seconds to actually be opposite of the expected response.
Response: With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. The FRS Form 1 has been modified to allow for adjustments (not exclusions) to the load and generation.		
Bonneville Power Administration	No	FRO definition - BPA feels uncomfortable supporting this standard when the ERO is given a blank check to FRO. The methodology for determining the FRO must be spelled out in detail in order to allow all entities an opportunity to comment on that methodology.
Response: The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is		

Organization	Yes or No	Question 1 Comment
necessary.		
SPP Standards Development	No	In the past tie line flow changes that did not have the expected response for the given frequency deviation have been excluded from the determination of Frequency Bias. It appears that this exclusion does not carry forth in the determination of Frequency Response Measure. Therefore, non-conforming loads, intermittent resources and other events/issues within a Balancing Authority could very well mask its natural frequency repsonse thereby setting the Balancing Authority's Frequency Bias and its Frequency Response Obligation incorrectly. Then the Balancing Authority is obligated to respond and will be measured for compliance against an incorrect value. This being the case, we can support the definition of Single Event Frequency Response Data but have reservations about Frequency Response Measure and Frequency Response Obligation.
Response: The SDT agrees with your concern regarding the definition of FRO and has revised the definition to read "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. The FRS Form 1 has been modified to allow for adjustments (not exclusions) to the load and generation. Note that based on other stakeholder concerns, the definition of SEFRD has been deleted.		
IRC Standards Review Committee	No	The definition of SEFRD will not work as described for a single BA Interconnection. There is no change in NI for frequency deviations. Similarly, the definition assumes all response is provided by change in Interchange and does not really reflect the frequency response of a contingent BA. Either the definition needs to be changed to accommodate single BA Interconnections (such as ERCOT and Hydro Quebec), or regional variances for them need to be written by the SDT. A BA's frequency response is composed of load frequency response, governor response, and, for BAs external to the resource loss, change in Net Interchange. Some approximation may be achieved by recognizing that the magnitude of frequency deviation is attenuated by load frequency response and governor response (or frequency activated demand response to reduce load). The definition of FRM specifies the median of all SEFRD observations reported annually. What is the technical basis for selecting the median rather than the mean? The definition of FRO raises questions. The discretely administered determination of FRO described in the draft Attachment A sets too stringent a requirement; particularly for the smaller Interconnections which may also have large size generation resources just as do the larger Interconnections. To "assure that Point C will not encroach on the first step UFLS" is significantly more stringent than existing and historical performance for those smaller Interconnections. Such assurance will assuredly prove to be very expensive.In fact, we question the need to define FRM and FRO since they can easily be stipulated in

Organization	Yes or No	Question 1 Comment
		the standard requirements. Having them defined and added to the ever-growing NERC glossary creates unnecessary work to maintain the glossary, unless these terms are used by other NERC standards for which consistent meaning need to be established. For example, R1 can easily be reworded as:”R1: Each Balancing Authority shall achieve a median of all Single Event Frequency Response Data observations reported annually on FRS Form 1 that is equal to or more negative than its contribution obligation to the total aggregate Frequency Response needed for reliable operation of an Interconnection assigned by the ERO.\ ”Similar wording changes can be made to the FRS Form 1 to eliminate the need to define these two terms.Further, the Attachment A states that the SDT is evaluating a risk based approach to establishing an Interconnection Frequency Response Obligation which can be based on a probability function. If the N-2 criteria is established, it will be unlikely to be possible to change that if the new approach is viewed as a reduction in required performance. As an example, in the ERCOT Interconnection, it is recognized that the present level of required frequency responsive reserve cannot in all scenarios assure that Point C will not encroach the first step of UFLS. The system conditions that exist for the encroachment to occur represent a small likelihood and would require the N-2 contingency to occur on something like the minimum hour of the minimum load day of the year. It has occurred one time in the history of ERCOT. Thus, it is less than once in ten years based upon actual history. The cost of precluding such an event would be astronomical.
Response: The SDT believes that the FRO and FRM definitions will be used in later revisions to the BAL group of standards and therefore is keeping the definitions in the standard so they can be added to the approved NERC Glossary of Terms. The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read “The Balancing Authority’s share of the required Frequency Response needed for the reliable operation of an Interconnection.” With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. The SDT has chosen the deterministic approach detailed in Attachment A as the method to use to allocate the Interconnection FRO to the BAs. The SDT is evaluating a probabilistic approach during the field trial.		
ERCOT	No	The definition of SEFRD will not work as described for a single BA Interconnection. There is no change in NI for frequency deviations. Similarly, the definition assumes all response is provided by change in Interchange and does not really reflect the frequency response of a contingent BA. Either the definition needs to be changed to accommodate single BA Interconnections (such as ERCOT and Hydro Quebec), or regional variances for them need to be written by the SDT. A BA’s frequency response is composed of load frequency response, governor response, and, for BAs external to the resource loss, change in Net Interchange. Some approximation may be achieved by recognizing that the magnitude of frequency deviation is attenuated by

Organization	Yes or No	Question 1 Comment
		load frequency response and governor response (or frequency activated demand response to reduce load). The definition of FRM specifies the median of all SEFRD observations reported annually. What is the technical basis for selecting the median rather than the mean? The definition of FRO raises questions. The discretely administered determination of FRO described in the draft Attachment A sets too stringent a requirement; particularly for the smaller Interconnections which may also have large size generation resources just as do the larger Interconnections. To “assure that Point C will not encroach on the first step UFLS” is significantly more stringent than existing and historical performance for those smaller Interconnections. Such assurance will assuredly prove to be very expensive. In fact, we question the need to define FRM and FRO since they can easily be stipulated in the standard requirements. Having them defined and added to the ever-growing NERC glossary creates unnecessary work to maintain the glossary, unless these terms are used by other NERC standards for which consistent meaning need to be established. For example, R1 can easily be reworded as:”R1: Each Balancing Authority shall achieve a median of all Single Event Frequency Response Data observations reported annually on FRS Form 1 that is equal to or more negative than its contribution obligation to the total aggregate Frequency Response needed for reliable operation of an Interconnection assigned by the ERO.” Similar wording changes can be made to the FRS Form 1 to eliminate the need to define these two terms.Further, the Attachment A states that the SDT is evaluating a risk based approach to establishing an Interconnection Frequency Response Obligation which can be based on a probability function. If the N-2 criteria is established, it will be unlikely to be possible to change that if the new approach is viewed as a reduction in required performance. As an example, in the ERCOT Interconnection, it is recognized that the present level of required frequency responsive reserve cannot in all scenarios assure that Point C will not encroach the first step of UFLS. The system conditions that exist for the encroachment to occur represent a small likelihood and would require the N-2 contingency to occur on something like the minimum hour of the minimum load day of the year. It has occurred one time in the history of ERCOT. Thus, it is less than once in ten years based upon actual history. The cost of precluding such an event would be astronomical.

Response: The SDT believes that the FRO and FRM definitions will be used in later revisions to the BAL group of standards and therefore is keeping the definitions in the standard so they can be added to the approved NERC Glossary of Terms.

The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard.

The SDT also agrees with your concern regarding the definition of FRO and has revised the definition to read “The Balancing Authority’s share of the required Frequency Response needed for the reliable operation of an Interconnection.”

With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.

The SDT has chosen the deterministic approach detailed in Attachment A as the method to use to allocate the Interconnection FRO to the BAs. The SDT is

Organization	Yes or No	Question 1 Comment
evaluating a probabilistic approach during the field trial.		
Progress Energy	No	The proposed definition for SEFRD assumes that there is no change in the Net Scheduled Interchange (NIS) as a result of the event. However, a dynamic schedule for load or generation based on data obtained with a two second scan rate will impact the NIS, and therefore the corresponding load or generation response will offset the change to NIA. Therefore, the definition of SEFRD should replace "NIA" with "change in NIA minus NIS".
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard.		
Energy Mark, Inc.	No	Comment 1: I agree with the definition of the Single Event Frequency Response Data. Comment 2: I do not agree that the Frequency Response Measure should be the median of all SEFRD observations reported annually on FRS Form 1. Comment 3: The regression values presented on FRS Form 1 have not been calculated correctly. Comment 4: Since the FRM is going to be used to set the value for the Frequency Bias Setting and the Frequency Bias Setting represents a straight line though the origin of zero frequency error and zero megawatt error, the best representation of the data for setting this paramater can be achieved through the use of a regression. Comment 5: Only a regression will weight the impact of each SEFRD correctly. The use of median or mean will not provide the best estimate for use as the Frequency Bias Setting. Comment 6: The standard has been written to include a samlple size (25) large enough to enable effective statistical methods of analysis. What justification is there to then ignor those well proven methods and revert to methods designed to address problems where the sample sizes are insufficient to support sound statistical analysis methods.
Response: (1) The SDT thanks you for your affirmative response, however several other stakeholders disagreed with the definition of SEFRD and the drafting team has removed the proposed definition from the revised standard. (2, 4, 5) With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process. (3) The SDT has corrected FRS Form 1. (6) Research conducted by the Frequency Response Standard Drafting Team (FR SDT) indicated that a Balancing Authority's FRM will converge to a reasonably stable value with 20 to 25 samples. The FR SDT as well as the NERC Frequency Response Initiative is evaluating other methods of FRM. The SDT is not ignoring methods of proven statistical design and the chosen method does require at least 25		

Organization	Yes or No	Question 1 Comment
samples.		
EKPC	No	These definitions should be revised to include specifics on how to calculate each term. The FRM calculation method should take into account large non-conforming loads. A median will not reflect the true nature of the system.
Response: The SDT does not believe the definition should include the specific calculation and therefore has incorporated the calculation methodology in Attachment A. The FRM calculation, using FRS Form 1, has been modified to now include adjustments. Based on analysis of data the SDT has determined that the median value is the proper method to be used in defining FRM.		
Duke Energy	No	The definition of SEFRD would conflict with any alternative measurement of frequency response. The SEFRD makes no provision for the impacts of generation loss experienced by a contingent BA, impacts of non-conforming loads, or impacts of schedule ramps. The FRM also makes no such provisions. The resulting FRM for a BA experiencing one or more of these impacts for one or more SEFRDs will be skewed and completely miss the intended measurement of the BA's response to frequency excursions. In addition, as it is not yet clear how provision of Frequency Response by one BA to meet a portion of another BA's requirement would be achieved, Duke Energy cannot say that a simple measure of the NIA against the frequency deviation will capture the net of the response desired. Regarding the definition of FRO, the industry should agree on the methodology which would be used for the ERO to determine the response desired for the Interconnection that is used for allocation of the FRO, and not leave it as a parameter subject to change outside of the standards process. The definition is only acceptable if the assignment by the ERO is based upon a methodology supported by the industry and subject to change only through the standards process.
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. The FRS Form 1 has been modified to allow for adjustments (not exclusions) to the load and generation. The methodology that the ERO will use for determining the FRO is now outlined in the new Attachment A. The industry will either accept or reject this methodology in the balloting phase of the standard.		
Associated Electric Cooperative, Inc.	No	1) SEFRD - I had to read this definition several times because "The individual sample of event data" is actually an internally calculated value derived from a set of event sample data, and not really a "sample" value at all. So, I believe the SEFRD definition needs further work.

Organization	Yes or No	Question 1 Comment
		2) FRM is defined by undefined terms “FRS” and “FRS Form 1”. 3) FRO – fine 4) FRS - “Frequency Response Survey”
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard. FRS Form 1 is the name of the form to be used for calculating FRM.		
Alberta Electric System Operator	No	The frequency response has 2 aspects: arresting frequency deviation (Point C) and deviation where frequency has settled (Point B). The proposed SEFRD and FRM seem all based on the Point B, however the intention in purpose statement is towards Point C... It is not clear to AESO that these proposed SEFRD and FRM based on settled frequency deviation (Point B) are technically sufficient to address the concern of arresting frequency deviation (Point C).
Response: The SDT recognizes that point C is the primary reliability concern. However, while Point B measurements have some data quality challenges to be mastered, point C measurements are not practical at this time for Balancing Authorities in an Interconnection with more than one Balancing Authority. The SDT intends to study point B and point C relationships of each Interconnection with more than one Balancing Authority to address this issue.		
Independent Electricity System Operator	No	We concur with the definitions for SEFRD, FRM and FRO but do not believe that the latter two terms (FRM and FRO) need to be defined since they can easily be stipulated in the standard requirements. Having them defined and added to the ever-growing NERC glossary creates unnecessary work to maintain the glossary, unless these terms are used by other NERC standards for which consistent meaning need to be established. For example, R1 can easily be reworded as:”R1: Each Balancing Authority shall achieve a median of all Single Event Frequency Response Data observations reported annually on FRS Form 1 that is equal to or more negative than its contribution obligation to the total aggregate Frequency Response needed for reliable operation of an Interconnection assigned by the ERO.”Similar wording changes can be made to the FRS Form 1 to eliminate the need to define these two terms.
Response: Several stakeholders indicated concerns with the definition of SEFRD and the team has removed this definition from the revised standard. The SDT believes that the FRO and FRM definitions will be used in later revisions to the BAL group of standards and therefore is keeping the definitions in the standard so they can be added to the approved NERC Glossary of Terms.		
FirstEnergy	Yes	For the definition of FRM, we are not clear as to the rationale for choosing the median value instead of the mean.
Response: The SDT thanks you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 1 Comment
With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		
Southern Company	Yes	Comments: The Frequency Response Measure should be based on either the median or average of all SEFR's as currently defined. Due to the varied nature of frequency responsive resources online it should never be based on meeting response on a single event.
Response: The SDT thanks you for your affirmative response and clarifying comment. With regards to use of the median for calculating FRM, in general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FR SDT have shown the Median to be less influenced by noise in the measurement process.		
Seattle City Light	Yes	
Manitoba Hydro	Yes	
ENBALA Power Networks	Yes	
NIPSCO	Yes	
NorthWestern Energy	Yes	
Kansas City Power & Light	Yes	
Arizona Public Service Company	Yes	
FMPP	Yes	
American Electric Power	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		

2. **The SDT has modified the definition for the term Frequency Bias Setting. The current definition and revised definition are shown below to show the changes proposed.**

Frequency Bias Setting

Current Definition in NERC Glossary: A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm, that allows the Balancing Authority to contribute its frequency response to the Interconnection.

Revised Definition: A value, (either a fixed or variable Frequency Bias), usually expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error equation that allows the Balancing Authority to contribute its Frequency Response to the Interconnection.

Do you agree with this new definition for Frequency Bias Setting? If not, please explain in the comment area.

Summary Consideration: Many of the commenters did not agree with the new definition proposed for Frequency Bias Setting. Several commenters recommend revising the Frequency Bias Setting definition and have offered suggestions for the SDT to consider. In response, the SDT has revised the Frequency Bias Setting definition to better address concerns raised by industry.

The revised definition is:

Frequency Bias Setting: 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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.

Some commenters also questioned if the definition of Frequency Response also needed to be revised, however in reviewing the current definition of Frequency Response the SDT believes that the current definition is both accurate and appropriate. Concern was also raised regarding what constitutes variable bias. - Fixed bias is a value approved by the ERO whereas variable bias is a methodology for determining the Frequency Bias Setting approved by the ERO.

Organization	Yes or No	Question 2 Comment
Santee Cooper	No	We suggest the following changes to the definition: A value, fixed or variable, expressed in MW/0.1 hertz, as part of a Balancing Authority's Area Control Error (ACE) equation that influences its Automatic Generation Control (AGC) to provide frequency response without secondary control action withdrawing the response.
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
ENBALA Power Networks	No	: ENBALA would modify the above as follows: A value, (either a fixed or variable Frequency Bias), usually

Organization	Yes or No	Question 2 Comment
		expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error algorithm equation that allows the Balancing Authority AGC System to ignore the export or import caused by the Primary Frequency Response.
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
Westar Energy	No	We propose the following:A value, (either a fixed or variable), expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error equation that allows the Balancing Authority to contribute its SECONDARY Frequency Response to the Interconnection.
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
EKPC	No	"Frequency Bias" should not be used in the definition."Usually" can be omitted.
Response: The SDT has modified the definition and "frequency bias" is not used in the revised definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
LG&E and KU Energy	No	We suggest the following changes to the definition: 1. Delete the word "usually" 2. Replace "set into" with "as part of". 3. Replace the remainder of the sentence following "Area Control Error equation" with "that influences its Automatic Generation Control (AGC) to provide its frequency response while Interconnection frequency is not at its scheduled value" - (The frequency bias does not allow a BA to contribute its frequency response to the Interconnection. The frequency bias term only affects the AGC response of the BA, which is part of its frequency response usually minutes after the initial event and is dependent upon generation units being on AGC control and capable of responding.) 4. The suggested changes would result in the following definition:A value, (either a fixed or variable Frequency Bias), expressed in MW/0.1 hertz as part of a Balancing Authority's Area Control Error (ACE) equation that influences its Automatic Generation Control (AGC) to provide its frequency response while Interconnection frequency is not at its scheduled value.
Response: The SDT did adopt the suggestion to remove, "set into" and replaced this phrase with, "included", however the team did not adopt the suggestion to		

Organization	Yes or No	Question 2 Comment
delete the word, 'usually' as the inclusion of this word recognizes that there may be rare instances when the Frequency Bias Setting could be expressed in other than MW/0.1 Hz. The SDT did not adopt the third proposed change because it can cause confusion since primary Frequency Response cannot be delivered by AGC. The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
SERC OC Standards Review Group	No	We suggest the following changes to the definition: 1. Delete "Frequency Bias" in the parenthetical expression - ("Frequency Bias" should not be used to define Frequency Bias) 2. Delete the word "usually" 3. Replace "set into" with "as part of" as defined in BAL-001. 4. Replace the remainder of the sentence following "Area Control Error equation" with "that influences its Automatic Generation Control (AGC) to provide its frequency response while Interconnection frequency is not at its scheduled value" - (The frequency bias does not allow a BA to contribute its frequency response to the Interconnection. The frequency bias term only affects the AGC response of the BA, which is usually minutes after the initial event and is dependent upon generation units being on AGC control and capable of responding.) 5. The suggested changes would result in the following definition"A value, fixed or variable, expressed in MW/0.1 hertz as part of a Balancing Authority's Area Control Error (ACE) equation that influences its Automatic Generation Control (AGC) to continue to provide its frequency response while Interconnection frequency is not at its scheduled value.
Response: The SDT has modified the definition and "frequency bias" is not used in the revised definition and the phase, "set into" was replaced with "included". The SDT did not adopt the suggestion to delete the word, 'usually' because there may be rare instances when the Frequency Bias Setting is expressed in other than MW/0.1 Hz. The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems."		
Midwest ISO Standards Collaborators	No	Given that frequency response is "contributed" long before AGC has an impact, "contribute" should probably be changed to "maintain". The goal is to ensure AGC does not withdraw frequency response and that it is maintained while frequency is depressed. We are not sure if Frequency Response has a precise enough definition and it is part of the definition of Frequency Bias Setting. The definition of Frequency Response really just reflects how it is measured. It does not define what it really is which is the dynamic response of load, generation, and other frequency responsive devices to a perturbation in frequency.

Organization	Yes or No	Question 2 Comment
		The drafting team should also consider resolving the definition of Frequency Bias. Is it needed? It is often confused with Frequency Bias Setting and is often used interchangeably with Frequency Response even though the meanings are slightly different.
Response: The SDT has modified the definition of Frequency Bias Setting. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT believes that based on the modified definition, the use of the term "contribution" better describes the action that has taken place. The SDT has reviewed the current definition of Frequency Response and believes that the current definition is both accurate and appropriate.		
We Energies	No	Given that frequency response is "contributed" long before AGC has an impact, "contribute" should probably be changed to "maintain." The goal is to ensure AGC does not withdraw frequency response and that it is maintained while frequency is depressed. We are not sure if Frequency Response has a precise enough definition and it is part of the definition of Frequency Bias Setting. The current NERC Glossary definition of Frequency Response really just reflects how it is measured, it does not define Frequency Response. Frequency Response is the dynamic real power response of load, generation, and other devices to a perturbation in frequency. The drafting team should also consider resolving the definition of Frequency Bias. Is it needed? It is often confused with Frequency Bias Setting and is often used interchangeably with Frequency Response even though the meanings are slightly different.
Response: The SDT has modified the definition of Frequency Bias Setting. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT believes that based on the modified definition, the use of the term "contribution" better describes the action that has taken place. The SDT has reviewed the current definition of Frequency Response and believes that the current definition is both accurate and appropriate.		
SPP Standards Development	No	We would suggest inserting 'secondary' in front of Frequency Response at the end of the sentence and delete 'Frequency Bias' following 'variable' at the beginning of the sentence.
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT believes that the modified definition is more appropriate than the recommended change. The SDT does not believe it is necessary to differentiate between primary and secondary Frequency Response in the definition.		
IRC Standards Review	No	The definition appears to be accurate, but where is "fixed" and "variable" Frequency Bias defined in the

Organization	Yes or No	Question 2 Comment
Committee		context of these requirements? Should it be Frequency Bias Setting, instead? "Fixed" seems to be straightforward, but what is "variable"? How often must Frequency Bias Setting change in order to be considered to be "variable"?
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." If the ERO provides the Frequency Bias Setting then it is considered fixed. If the ERO accepts a methodology for determining the Frequency Bias Setting then it is considered variable.		
ERCOT	No	The definition appears to be accurate, but where is "fixed" and "variable" Frequency Bias defined in the context of these requirements? Should it be Frequency Bias Setting, instead? "Fixed" seems to be straightforward, but what is "variable"? How often must Frequency Bias Setting change in order to be considered to be "variable"?
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." If the ERO provides the Frequency Bias Setting then it is considered fixed. If the ERO accepts a methodology for determining the Frequency Bias Setting then it is considered variable.		
Progress Energy	No	A bias, 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's Frequency Response contribution to the interconnection, and prevent response withdrawal through secondary control systems. The changes suggested are to clarify that biasing of the ACE equation "allow[s]" primary frequency response to continue beyond the initial event window by accounting for it in the ACE input to secondary control systems (i.e. AGC). It's important to note that Primary Frequency Response will occur no matter what the Bias value is set to in the ACE equation, and biasing "supports" the response until the frequency is restored".
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT believes that the revised definition agrees with your comment related to supporting the response until frequency is restored. The SDT also believes that it is impossible to "prevent" withdrawal and that you can only try to discourage withdrawal.		
NIPSCO	No	Frequency Bias and Frequency Response are not the same thing and that may be why "F" & "R" were not

Organization	Yes or No	Question 2 Comment
		capitalized in the present definition. I think the word "secondary" should appear per R2 finishing something like this: "to contribute to secondary (non-immediate)Interconnection frequency control.", removing Frequency Response altogether.(I do understand that you are bringing the FR and Bias closer together).
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT believes that the modified definition is more appropriate than the recommended change. The SDT does not believe it is necessary to differentiate between primary and secondary Frequency Response in the definition.		
Energy Mark, Inc.	No	Comment 7: The definition should be:"A value, (either a fixed or variable Frequency Bias), usually expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error equation that indicates to the Balancing Authority its contribution of Frequency Response to the Interconnection. Comment 8: The Frequency Bias Setting does not allow or disallow the Frequency Response to be contributed. The BA will contribute its natural Frequency Response to the interconnection through the independent actions of its loads and generators. The only influence that the Frequency Bias Setting has is that it causes the AGC System, and hopefully other outer-loop control systems, to include that natural Frequency Response when developing control actions to implement through AGC in response to BA balancing requirements in a time frame well after the Frequency Response has been provided by the independent actions of its loads and generators.
Response: The SDT has modified the definition. The definition now reads "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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems." The SDT agrees with comment #8.		
American Electric Power	No	If "the proposed standard's intent is to collect data needed to accurately analyze existing Frequency Response, set a minimum Frequency Response obligation, provide a uniform calculation of Frequency Bias Settings that transition to values closer to Frequency Response, and encourage coordinated AGC operation", it appears the current and stated definition is precluding the process for determination of the Frequency Bias Setting itself. I believe it is too early to state in definition the frequency bias setting to be based on MW/0.1 Hz, when this appears to be more of the expected response. Using the word usually does not appear to be defining anything.To eventually get to an acceptable performance measure with reliability basis the project needs to be expanded to also address associated

Organization	Yes or No	Question 2 Comment
		governor droop issues, which inherently affect response. When the current definition references using “either a fixed or variable Frequency Bias”, it does not state whether or not to be applied in the calculation to either load or generation. The current Standard uses 1% of yearly estimated peak demand for BAs that serve load, when the actual load at time of disturbance could be greatly different. Response is more directly related to the amount of Generation on-line and active AGC within the BA at time of trip.MW/0.1 Hz states more of expected result of response than defining Frequency Bias Setting.
Response: The SDT has modified the definition. The definition now reads “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’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.”The “MW/0.1 Hz” term represents the units of Frequency Bias and is not intended to reference magnitude. Issues dealing with governor droop are outside of the scope of the industry approved SAR. The SDT agrees with the last comment which is why the SDT also supports using a variable bias where appropriate.		
Duke Energy	No	Duke Energy would suggest not using “Frequency Bias” in the definition of “Frequency Bias Setting”. In addition, Duke Energy would like to point out that ACE does not allow Frequency Response; response will occur with or without the ACE equation. The Frequency Bias Setting is needed so that the AGC does not negate what may be provided in frequency response. The bias component of ACE provides the feedback so that a BA may sustain the intended amount of response with secondary control as long as Actual Frequency deviates from Scheduled Frequency. Duke Energy would suggest the following:”A fixed or variable value usually expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error equation to bias the control of resources so that Interconnection frequency is driven toward the Scheduled Frequency.”
Response: The term Frequency Bias has been removed from the definition. The SDT has modified the definition. The definition now reads “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’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.”		
Associated Electric Cooperative, Inc.	No	SEFRD - I had to read this definition several times because “The individual sample of event data” is actually an internally calculated value derived from a set of event sample data, and not really a “sample” value at all. So, I believe the SEFRD definition needs further work.
Response: The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard.		

Organization	Yes or No	Question 2 Comment
MRO's NERC Standards Review Subcommittee	No	
Southern Company	Yes	Frequency Bias SettingA value, (either a fixed or variable Frequency Bias), usually expressed in MW/0.1 Hz, set into a Balancing Authority Area Control Error algorithm equation that allows the Balancing Authority to contribute its frequency Frequency rResponse to the Interconnection. Comments: Not sure the word “allows” is the right word. Perhaps use something in terms of preventing withdrawal of Primary Frequency Response with words like “...equation that prevents the withdrawal of the Balancing Authority’s Primary Frequency Response to the Interconnection.”
Response: The SDT thanks you for your affirmative response and clarifying comments. The revised definition does not use the word, “allows.” The definition now reads “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’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.”		
FirstEnergy	Yes	Although we support the definition, we suggest the word “contribute” be changed to “maintain”.
Response: The SDT thanks you for your affirmative response and clarifying comments. The SDT has modified the definition. The definition now reads “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’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.” The SDT believes that based on the modified definition, the use of the term “contribution” better describes the action that has taken place.		
Patterson Consulting, Inc.	Yes	
Beacon Power Corporation	Yes	
NorthWestern Energy	Yes	
Kansas City Power & Light	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Alberta Electric System Operator	Yes	
Independent Electricity System Operator	Yes	
FMPP	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
South Carolina Electric and Gas		We suggest the following changes to the definition: 1. Delete “Frequency Bias” in the parenthetical expression - (“Frequency Bias” should not be used to define Frequency Bias) 2. Delete the word “usually” 3. Replace “set into” with “as part of” as defined in BAL-001. 4. Replace the remainder of the sentence following “Area Control Error equation” with “that influences its Automatic Generation Control (AGC) to provide its frequency response while Interconnection frequency is not at its scheduled value” - (The frequency bias does not allow a BA to contribute its frequency response to the Interconnection. The frequency bias term only affects the AGC response of the BA, which is part of its frequency response usually minutes after the initial event and is dependent upon generation units being on AGC control and capable of responding.) 5. The suggested changes would result in the following definition”A value, fixed or variable, expressed in MW/0.1 hertz as part of a Balancing Authority’s Area Control Error (ACE) equation that influences its Automatic Generation Control (AGC) to provide its frequency response while Interconnection frequency is not at its scheduled value.
Response: The term, “Frequency Bias” was deleted, the phrase, “set into” was replaced with, “included in”. The other suggestions were not adopted. The SDT has modified the definition. The definition now reads “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’s Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.” The SDT believes that the modified definition addresses your concerns but provides for additional clarity as to the action that has taken place.		
Northeast Power Coordinating Council		Refer to the response to Question 17.

Organization	Yes or No	Question 2 Comment
Response: Please refer to the SDT response to Question 17.		

3. The proposed purpose statement in the draft standard is: To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to schedule. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

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

Summary Consideration: Several of the commenters agree with the purpose statement of the draft standard as written. Most of the feedback received disagreeing with the purpose statement reflects general comments and suggestions for the SDT to consider. A major concern identified is that the minimum level of Frequency Bias Setting established needs to be determined based on extensive data analysis of field trial results. Some commenters even stated that the standard should not be revised until the field trial is completed, performance criteria and measures determined, and results vetted by industry. Several commenters expressed concern with making the Balancing Authority the only entity responsible for maintaining interconnection frequency and arresting frequency decline; with an observation that the purpose statement presumes that each Balancing Authority must have generation online to meet a predetermined frequency response obligation. It was pointed out that on occasion small Balancing Authorities may not have generation online and instead rely on load regulation and energy agreements to meet their energy needs. Another commenter indicated that since NERC and FERC have differentiated Frequency Response from Frequency Regulation, the standard should only apply to unplanned contingencies that occur.

In response to these general comments the SDT notes that the minimum Frequency Response level used during the field trial uses a deterministic approach and the actual level of Frequency Response required in the final version of the draft standard will be based on field trial results. Issues involving governor droop, dead-band settings, and governor operation are outside the scope of the project's approved SAR. The purpose statement does not mandate generation dispatch for Frequency Response. This standard only prescribes a minimum Frequency Response obligation for reliable BES operation. Each entity must determine how to meet its Frequency Response obligation using existing resources and agreements.

Another commenter noted that the purpose statement addresses several concepts that do not share a common timeframe. In response, the SDT has revised Attachment A to explain the relationship for the different time frames associated with these concepts.

Organization	Yes or No	Question 3 Comment
MRO's NERC Standards Review Subcommittee	No	In general, we don't have significant issues with a standard that attempts to establish a minimum Frequency Response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis based on the field trial, based on the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference and based on the plan outlined in NERC's October 25, 2010 compliance filing.
Response: The SDT thanks you for your comment. For the field trial, the minimum level of response needed uses a deterministic approach. The actual level of response required may be established in the final version of the standard using field trial information obtained. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012		

Organization	Yes or No	Question 3 Comment
Modifications to this schedule require both NERC and FERC approval.		
Midwest ISO Standards Collaborators	No	In general, we don't have significant issues with a standard that attempts to establish a minimum Frequency Response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis based on the field trial, based on the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference and based on the plan outlined in NERC's October 25, 2010 compliance filing.
Response: The SDT thanks you for your comment. For the field trial, the minimum level of response needed uses a deterministic approach. The actual level of response required may be established in the final version of the standard using field trial information obtained. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012. Modifications to this schedule require both NERC and FERC approval.		
We Energies	No	In general, we don't have significant issues with a standard that attempts to establish a minimum Frequency Response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis, field trial data, the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference, and the plan outlined in NERC's October 25, 2010 compliance filing.
Response: The SDT thanks you for your comment. For the field trial, the minimum level of response needed uses a deterministic approach. The actual level of response required may be established in the final version of the standard using field trial information obtained. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012. Modifications to this schedule require both NERC and FERC approval.		
LG&E and KU Energy	No	The proposed purpose statement as provided in this question is not the same as the purpose statement for BAL-003-1 as posted on the Project 2007-12 page of the NERC website. The posted purpose on the NERC website is:To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored. To schedule and provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.The version posted in the question appears to correct errors in the last sentence of the purpose statement given in the project page. We do not agree with the purpose statement as posted on the project page.In addition, we suggest the following edits to what appears to be a corrected purpose statement as provided in this question:To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations due to contingencies on the interconnected BES and supporting frequency until the frequency is restored to schedule. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting. As NERC/FERC has differentiated Frequency Response from Frequency Regulation, the standards

Organization	Yes or No	Question 3 Comment
		addressing Frequency Response should clearly be related to unplanned contingencies occurring on the interconnected BES.
Response: The SDT believes adequate Frequency Response is important during both normal and emergency operations however it is easier to measure Frequency Response during a contingency which is why the SDT favors this rationale.		
IRC Standards Review Committee	No	If this is really intended to be a Field Trial, it should be written as such and the standard should not be developed or promulgated until the Field Trial has accomplished its purpose and the performance criteria and measures have been determined. We request that the results of the Field Trial should be published and discussed BEFORE any changes are made. The standard should be put into place later; it is premature at this time. Since this is to be a data gathering process to be used to determine appropriate performance parameters, the purpose statement of the Field Trial should be changed to read as follows:To determine require sufficient Frequency Response arranged by from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by responding to and arresting frequency deviations and supporting frequency until the frequency is restored to schedule. To identify and establish provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting and Frequency Response Obligation.We should not write the new standard and its requirements until this Field Trial work has been accomplished; to do so possibly would result in difficulty changing the standard requirements based upon Field Trial results. Further, while we do not have any issue with the general intent of the scope statement, we have a difficulty seeing the BA being the only entity held responsible for maintaining interconnection frequency and arresting frequency deviations. When there is a sudden and sizable change to system resource or demand, the first response to a frequency deviation caused by this change would be the generators' governors. This will provide a mitigating effect for the immediate seconds up to minutes. The frequency bias setting will then kick in to supplement the mitigation need. The governors are owned by the Generator Owners; the BAs do not own these facilities and hence can do little to address frequency response during this initial period.To hold only the BA responsible for maintaining interconnection frequency and arresting frequency deviations would be inappropriate. The industry needs to have a discussion to determine who should be held responsible for providing governor responses immediately following an event, and by what mechanism, and for implementing additional measures thereafter. We suggest that BAL-003 development be withheld until this discussion takes place and a decision is made on who and how the governor response shall be provided.
Response: The original SAR was for data collection. The SDT developed a supplemental SAR to address the FERC directives. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012. Modifications to this schedule require both NERC and FERC approval. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification		

Organization	Yes or No	Question 3 Comment
standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators. The purpose of the standard is to establish a minimum Frequency Response threshold that prevents unreliable BES operation. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators.		
ISO New Engand Inc.	No	If this is really intended to be a Field Trial, it should be written as such and the standard should not be developed or promulgated until the Field Trial has accomplished its purpose and the performance criteria and measures have been determined. The standard should be put into place later; it is premature at this time. Since this is to be a data gathering process to be used to determine appropriate performance parameters, the purpose statement of the Field Trial should be changed to read as follows:To determinerequire sufficient Frequency Response arranged by from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by responding to and arresting frequency deviations and supporting frequency until the frequency is restored to schedule. To identify and establishprovide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting and Frequency Response Obligation.We should not write the new standard and its requirements until this Field Trial work has been accomplished; to do so possibly would result in difficulty changing the standard requirements based upon Field Trial results. Further, while we do not have any issue with the general intent of the scope statement, we have a difficulty seeing the BA being the only entity held responsible for maintaining interconnection frequency and arresting frequency deviations. When there is a sudden and sizable change to system resource or demand, the first response to a frequency deviation caused by this change would be the generators' governors. This will provide a mitigating effect for the immediate seconds up to minutes. The frequency bias setting will then kick in to supplement the mitigation need. The governors are owned by the Generator Owners; the BAs do not own these facilities and hence can do little to address frequency response during this initial period.To hold only the BA responsible for maintaining interconnection frequency and arresting frequency deviations would be inappropriate. The industry needs to have a discussion to determine who should be held responsible for providing governor responses immediately following an event, and by what mechanism, and for implementing additional measures thereafter. We suggest that BAL-003 development be withheld until this discussion takes place and a decision is made on who and how the governor response shall be provided.
Response: The original SAR was for data collection. The SDT developed a supplemental SAR to address the FERC directives. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012.		

Organization	Yes or No	Question 3 Comment
Modifications to this schedule require both NERC and FERC approval. The purpose of the standard is to establish a minimum Frequency Response threshold that prevents unreliable BES operation. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators.		
ERCOT	No	If this is really intended to be a Field Trial, it should be written as such and the standard should not be developed or promulgated until the Field Trial has accomplished its purpose and the performance criteria and measures have been determined. We request that the results of the Field Trial should be published and discussed BEFORE any changes are made. The standard should be put into place later; it is premature at this time. Since this is to be a data gathering process to be used to determine appropriate performance parameters, the purpose statement of the Field Trial should be changed to read as follows:To determine require sufficient Frequency Response arranged by from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by responding to and arresting frequency deviations and supporting frequency until the frequency is restored to schedule. To identify and establish provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting and Frequency Response Obligation.We should not write the new standard and its requirements until this Field Trial work has been accomplished; to do so possibly would result in difficulty changing the standard requirements based upon Field Trial results. Further, while we do not have any issue with the general intent of the scope statement, we have a difficulty seeing the BA being the only entity held responsible for maintaining interconnection frequency and arresting frequency deviations. When there is a sudden and sizable change to system resource or demand, the first response to a frequency deviation caused by this change would be the generators' governors. This will provide a mitigating effect for the immediate seconds up to minutes. The frequency bias setting will then kick in to supplement the mitigation need. The governors are owned by the Generator Owners; the BAs do not own these facilities and hence can do little to address frequency response during this initial period.To hold only the BA responsible for maintaining interconnection frequency and arresting frequency deviations would be inappropriate. The industry needs to have a discussion to determine who should be held responsible for providing governor responses immediately following an event, and by what mechanism, and for implementing additional measures thereafter. We suggest that BAL-003 development be withheld until this discussion takes place and a decision is made on who and how the governor response shall be provided.
Response: The original SAR was for data collection. The SDT developed a supplemental SAR to address the FERC directives. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012. Modifications to this schedule require both NERC and FERC approval.		

Organization	Yes or No	Question 3 Comment
The purpose of the standard is to establish a minimum Frequency Response threshold that prevents unreliable BES operation. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators.		
Kansas City Power & Light	No	This purpose statement presumes that each Balancing Authority (BA) will have generation online to meet a predetermined frequency response obligation. There are many small BA's that do not have any generation online and rely on load regulation agreements and energy agreements to provide their energy needs during parts of the year. This purpose statement would not allow a BA to operate without generation online.
Response: The purpose statement does not mandate generation dispatch for Frequency Response. This standard only prescribes a minimum Frequency Response obligation for reliable BES operations. Each entity must determine how to meet this obligation using existing resources and agreements.		
NIPSCO	No	Yes, "Interconnection frequency", small "f".
Response: The SDT thanks you for this comment and has corrected the error.		
American Electric Power	No	AEP believes the statement should read "To require sufficient Frequency Response from governors and AGC of Generators within the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to schedule.To provide consistent methods for measuring Frequency Response from governors and AGC of Generators within the Balancing Authority for determining the overall Frequency Bias Setting threshold.Since Generators are directly responsible for response, applicability must be added to Generator Operators.
Response: The drafting team disagrees with this recommendation because the FERC Order 693 requires a technology neutral performance standard for the purpose of providing Frequency Response.		
Patterson Consulting, Inc.	No	The purpose should not expect Frequency Response to maintain frequency beyond a few minutes, perhaps 15 minutes for example. This purpose statement suggests the requirements will be "...to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and support frequency until the frequency is restored to schedule..." The phrase "until the frequency is restored to schedule" is problematic since regulation must bring frequency to schedule. Frequency Response, and the associated requirements, should not be expected to substitute for poor regulation beyond the first few minutes.
Response: The focus of the standard is to establish sustainable primary frequency control which can seamlessly coordinate with secondary frequency control for maintaining system frequency.		

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	No	We do not have any issue with the general intent of the scope statement, but have a difficulty in seeing the BA being the only entity held responsible for maintaining interconnection frequency and arresting frequency deviations. When there is a sudden and sizable change to system resource or demand, the system frequency will change. The first response to such deviation would be the generators' governors. This will provide a mitigating effect for the immediate seconds up to minutes. The frequency bias setting will then kick in to supplement the mitigation need. To hold only the BA responsible for maintaining interconnection frequency arresting frequency deviations would be only part of the solution. The industry needs to have a discussion to determine who should be held responsible for providing governor responses, and by what mechanism. We suggest that BAL-003 development be withheld until this discussion takes place and a decision is made on who and how the governor response shall be provided.
Response: The SDT thanks you for your comment. This issue concerning the BA being the only entity being held responsible has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT encourages entities to develop a SAR to address generators. For the field trial, the minimum level of response needed uses a deterministic approach. The actual level of response required may be established in the final version of the standard using field trial information obtained. The SDT does not agree with your comment concerning withholding the development of a standard addressing Frequency Response. The development of a standard addressing Frequency Response was identified in FERC Order 693. FERC further directed the ERO to finalize a standard addressing Frequency Response in an order in February 2010 within six (6) months which they later granted an extension. The project schedule adopted for the development of the BAL-003 standard has been approved by the FERC and includes filing a standard by May, 2012. Modifications to this schedule would require both NERC and FERC approval.		
ENBALA Power Networks	Yes	ENBALA strongly agrees that a Frequency Response standard is necessary to ensure reliable operation of the bulk power system. We fully support all efforts to understand the declining trend, and the development of accurate models, of Frequency Response in each Interconnection.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Manitoba Hydro	Yes	The new more likely improved method of measuring Frequency Response is welcome. This should be an improvement over the existing methods of using 1% of projected peak load, or average of DCS events. Calculating projected peaks leave lots of room for error and limiting calculations to only DCS events likely does not reflect accurate BIAS.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Alberta Electric System Operator	Yes	The purpose statement mentioned arresting deviation, restored to schedule and frequency bias setting, which are all at different time frames. The AESO suggests that NERC provide some clarification of the relationships for the different time frames.
Response: The SDT thanks you for your affirmative response and clarifying comment. Refer to Attachment A for clarification of the relationships for the different time frames.		
Duke Energy	Yes	
Seattle City Light	Yes	
Santee Cooper	Yes	
FirstEnergy	Yes	
Bonneville Power Administration	Yes	
SPP Standards Development	Yes	
SERC OC Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Progress Energy	Yes	
NorthWestern Energy	Yes	
Energy Mark, Inc.	Yes	
Beacon Power Corporation	Yes	

Organization	Yes or No	Question 3 Comment
Westar Energy	Yes	
FMPP	Yes	
EKPC	Yes	
South Carolina Electric and Gas	Yes	
Associated Electric Cooperative, Inc.	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		

4. Requirement 1 identifies a minimum level of Frequency Response.

R1. Each Balancing Authority shall achieve a Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO).

Do you agree with the concept that a Balancing Authority should be required to achieve a minimum level of Frequency Response and the method for measurement? If not, please explain in the comment area.

Summary Consideration: Most commenters supported the concept however a significant majority did not agree with the method for measurement. In general commenters indicated the sample size of 25 events for determining FRM is too small; insufficient information was provided to address the use of variable bias; the FRM and FRO definitions were unclear with questionable determination methods; and the standard should reference Reserve Sharing Groups. Some commenters also indicated that the measure may not apply to a single BA interconnection; that the draft standard dictated how compliance is provided with respect to Attachment A and FRS Form 1 references; that requirements would not allow a BA to operate without generation online; and expressed concern that the BA may not own and operate resources yet will still have the compliance obligation.

The SDT is currently evaluating a probabilistic method for determining the FRO. After consideration of industry comments, the SDT converted Attachment A into two documents - a calculation methodology included with the standard, and a separate supporting document providing requirement rationale. The SDT revised the definitions for FRO & FRM; incorporated Reserve Sharing Groups into the draft standard; modified FRS Form 1 to allow for adjustments; and clarified how an entity is to show compliance. The SDT also provided an explanation addressing the use of Variable Bias and provided an administrative procedure for the ERO's FRO determination.

R1. Each Balancing Authority or Reserve Sharing Group (RSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency Response in the Interconnection.

Organization	Yes or No	Question 4 Comment
Santee Cooper	No	The concept seems reasonable but since the measure of compliance (FRM) is determined only after the 25 events are identified; it is a lagging indicator. The BA may have to ensure it measures all frequency excursions and develops its own leading indicator to ensure compliance following year end.
Response: The SDT agrees that the measure is a lagging indicator and recommends that the list of reportable events be posted on a quarterly basis.		
LG&E and KU Energy	No	The concept seems reasonable but since the measure of compliance (FRM) is determined only after the 25 events are identified; it is a lagging indicator. The BA may have to ensure it measures all frequency

Organization	Yes or No	Question 4 Comment
		excursions and develops its own leading indicator to ensure compliance following year end. A sample CPS bounds report should be considered, perhaps based on 2010 numbers, to demonstrate how FRM submitted would translate to FRO frequency bias settings and how it will affect the L10 values
Response: The SDT agrees that the measure is a lagging indicator and recommends that the list of reportable events be posted on a quarterly basis. The SDT will provide samples to illustrate the interaction of FRO, FRM, and frequency bias settings at the conclusion of the field trial.		
SERC OC Standards Review Group	No	The concept seems reasonable but since the measure of compliance (FRM) is determined only after the 25 events are identified; it is a lagging indicator. The BA may have to ensure it measures all frequency excursions and develops its own leading indicator to ensure compliance following year end. A sample CPS bounds report should be considered, perhaps based on 2010 numbers, to demonstrate how FRM submitted would translate to FRO frequency bias settings and how it will affect the L10 values.
Response: The SDT agrees that the measure is a lagging indicator and recommends that the list of reportable events be posted on a quarterly basis. The SDT will provide samples to illustrate the interaction of FRO, FRM, and frequency bias settings at the conclusion of the field trial.		
South Carolina Electric and Gas	No	The concept seems reasonable but since the measure of compliance (FRM) is determined only after the 25 events are identified; it is a lagging indicator. The BA may have to ensure it measures all frequency excursions and develops its own leading indicator to ensure compliance following year end. A sample CPS bounds report should be considered, perhaps based on 2010 numbers, to demonstrate how FRM submitted would translate to FRO frequency bias settings and how it will affect the L10 values.
Response: The SDT agrees that the measure is a lagging indicator and recommends that the list of reportable events be posted on a quarterly basis. The SDT will provide samples to illustrate the interaction of FRO, FRM, and frequency bias settings at the conclusion of the field trial.		
MRO's NERC Standards Review Subcommittee	No	In general, we don't have significant issues with a standard that attempts to establish a minimum frequency response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis based on the field trial, based on the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference and based on the plan outline in NERC's October 25, 2010 compliance filing. The effects of the nonconforming load should be considered in the calculation of the frequency response obligation in order to get accurate results.
Response: The minimum level of response selected for the field trial uses a deterministic approach. The actual level of response specified in the final version of the draft standard may be based on analysis of data obtained from the field trial.		

Organization	Yes or No	Question 4 Comment
The SDT is using a FERC approved project schedule to develop the BAL-003 standard and includes filing a standard by May, 2012.. Any modification to the project schedule will require both NERC and FERC approval. The deterministic allocation method does not consider the effects of nonconforming load.		
Midwest ISO Standards Collaborators	No	In general, we don't have significant issues with a standard that attempts to establish a minimum frequency response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis based on the field trial, based on the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference and based on the plan outline in NERC's October 25, 2010 compliance filing.
Response: The minimum level of response selected for the field trial uses a deterministic approach. The actual level of response specified in the final version of the draft standard may be based on analysis of data obtained from the field trial. The SDT is using a FERC approved project schedule to develop the BAL-003 standard and includes filing a standard by May, 2012.. Any modification to the project schedule will require both NERC and FERC approval.		
We Energies	No	In general, we don't have significant issues with a standard that attempts to establish a minimum frequency response performance level. However, we caution the drafting team that the minimum level established needs to be determined based on an extensive data analysis, field trial data, the Frequency Response Initiative Work Plan that NERC filed in response to the Commission's September 23 technical conference, and the plan outline in NERC's October 25, 2010 compliance filing.
Response: The minimum level of response selected for the field trial uses a deterministic approach. The actual level of response specified in the final version of the draft standard may be based on analysis of data obtained from the field trial. The SDT is using a FERC approved project schedule to develop the BAL-003 standard and includes filing a standard by May, 2012.. Any modification to the project schedule will require both NERC and FERC approval.		
Bonneville Power Administration	No	BPA agrees that there should be a minimum level of Frequency Response, but disagree with the way the measure is obtained in the requirement. o R1 - BPA suggests replacing "achieve" with "calculate". Achieve: indicates it is a performance. o R1 - BPA does not agree with the requirements in Attachment A not being in the standard. These should not be modified without full review and voting by members. o R1 - BPA believes that there should be more description on Variable Bias. What variable bias number should we use: average, minimum, peak for the event? BPA feels that the peak bias of each event would be appropriate.
Response: The SDT believes the intent of the standard is for each BA to "achieve" its Frequency Response Obligation.		

Organization	Yes or No	Question 4 Comment
The SDT is not incorporating additional standard requirements by means of Attachment A information however the SDT recognizes the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and describe the calculation methodology utilized. The second document will explain the rationale for the requirements as supplemental standard information. Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions. The SDT agrees Variable Bias requires more description and will review this concern during the field trial.		
IRC Standards Review Committee	No	The SRC agrees that a Frequency Response of some minimum level for each Interconnection should be achieved. However, the measure as described does not apply to all Interconnections. It does not apply to single BA Interconnections such as ERCOT and Hydro Quebec. This requirement should be added later-not included now; and it should clarify what the BA must do and what the response providers must do. BAs do not own and operate the resources. An entity which does own or operate the resources may also be registered as a BA, but an entity which does not own or operate resources may also be registered as a BA. Therefore, it is important to detail what a BA must do and also to detail what the resource owner or operator must do. The resource owner may be registered as a GO or a TO or even a DP. The resource operator may be registered as a GOP, a TOP, or a LSE. The BA must establish an operations plan, using data provided to it by the resource owners and or operators, that will meet the performance requirements. The BA must then deploy the proper amount of response through AGC or verbal instructions to supplement the automatic responses that the resources will provide, must calculate the actual responses after-the-fact, and report the performance as required. The resources must, as standards already provide, comply with the deployments and instructions provided by the BA. However, if an entity which is functioning as a BA does not own its resources, nor does it directly operate those resources, the BA cannot ensure the achievement. The standard must not create an organizational or contractual arrangement that dictates how the compliance is provided. It should state what must be done, not how. If entities choose to write and enter into such arrangements, that should be permissible, but not required. Specific to R1, the wording does not correspond to the figures shown in the FRS (Form 1) in that the FRM (the median) is -14.5 whereas the FRO is -15.8. The FRO is more negative than the FRM, which does not seem to correspond to what's stipulated in R1 (FRM to be equal or more negative than its FRO).
Response: This standard is intended to apply to all Interconnections. The SDT has modified the definition for FRO to read, "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." The standard does not dictate a particular generation dispatch strategy. The standard only prescribes a minimum obligation. The entity must determine how to meet this minimum obligation. FRS Form 1 has been revised to allow for adjustments.		
ERCOT	No	The SRC agrees that a Frequency Response of some minimum level for each Interconnection should be achieved. However, the measure as described does not apply to all Interconnections. It does not apply to

Organization	Yes or No	Question 4 Comment
		single BA Interconnections such as ERCOT and Hydro Quebec. This requirement should be added later-not included now; and it should clarify what the BA must do and what the response providers must do. BAs do not own and operate the resources. An entity which does own or operate the resources may also be registered as a BA, but an entity which does not own or operate resources may also be registered as a BA. Therefore, it is important to detail what a BA must do and also to detail what the resource owner or operator must do. The resource owner may be registered as a GO or a TO or even a DP. The resource operator may be registered as a GOP, a TOP, or a LSE. The BA must establish an operations plan, using data provided to it by the resource owners and or operators, that will meet the performance requirements. The BA must then deploy the proper amount of response through AGC or verbal instructions to supplement the automatic responses that the resources will provide, must calculate the actual responses after-the-fact, and report the performance as required. The resources must, as standards already provide, comply with the deployments and instructions provided by the BA. However, if an entity which is functioning as a BA does not own its resources, nor does it directly operate those resources, the BA cannot ensure the achievement. The standard must not create an organizational or contractual arrangement that dictates how the compliance is provided. It should state what must be done, not how. If entities choose to write and enter into such arrangements, that should be permissible, but not required. Specific to R1, the wording does not correspond to the figures shown in the FRS (Form 1) in that the FRM (the median) is -14.5 whereas the FRO is -15.8. The FRO is more negative than the FRM, which does not seem to correspond to what's stipulated in R1 (FRM to be equal or more negative than its FRO).
Response: This standard is intended to apply to all Interconnections. The SDT has modified the definition for FRO to read, "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." The standard does not dictate a particular generation dispatch strategy. The standard only prescribes a minimum obligation. The entity must determine how to meet this minimum obligation. FRS Form 1 has been revised to allow for adjustments.		
Kansas City Power & Light	No	This requirement presumes that each Balancing Authority (BA) will have generation online to meet a predetermined frequency response obligation. There are many small BA's that do not have any generation online and rely on load regulation agreements and energy agreements to provide their energy needs during parts of the year. This requirement would not allow a BA to operate without generation online. Under Requirement 1, item 2a in Attachment A suggests governor deadband as 36MHz (Megahertz). Suggest what is intended is 36mHz (millihertz). The Frequency Response Obligation determination for the interconnection as described in Attachment A is a crude method and will result in obligations that will exceed the FRO that is intended. This will result in additional cost to BA's that is unnecessary to achieve the purpose of maintaining sufficient generation online to arrest frequency degradation events caused by loss of generating resources.

Organization	Yes or No	Question 4 Comment
		The current NERC method for calculating a BA's actual frequency response are inaccurate and provide misleading guidance in the actual frequency response of a BA. These methods need considerable improvement before any attempts to hold a BA to an expected level of frequency response as this proposal has stated.
Response: The standard does not dictate a particular generation dispatch strategy. The standard only prescribes a minimum obligation. The entity must determine how to meet this minimum obligation. The SDT has removed the reference to governor deadband. The minimum level of response selected for the field trial uses a deterministic approach. The actual level of response specified in the final version of the draft standard may be based on analysis of data obtained from the field trial. The SDT is also evaluating a probabilistic method for determining the FRO. The SDT has modified FRS Form 1 to correctly calculate Frequency Response.		
Southern Company	No	Comments: Proposed Standard Comment 1: BAL-003-1, Requirement R1. The requirement should be made less prescriptive by removing references to Attachment A and FRS Form 1. The responsible entity should understand the fundamental and basic requirement - to achieve a Frequency Response Measure. Where the methodology is specified or how the BA is supposed to achieve it should be a matter of compliance and/or implementation and not a part of the basic requirement. Proposed language is as follows: Each Balancing Authority shall achieve a Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO).
Response: The SDT believes that Requirement 1 needs to reference FRS Form 1 in order for the calculation methodology to be consistent for all interconnections and has removed the reference to Attachment A. The SDT has also revised FRS Form 1 to correctly calculate Frequency Response and to allow for adjustments.		
Progress Energy	No	Progress Energy believes the Eastern Interconnection does not have the same issues with frequency experienced in the other two interconnections, and that load response is significant enough in the interconnection to arrest and stabilize frequency as long as BAs do not withdraw that effect (accurate biasing of the ACE equation). We also believe this standard should reference standrd PRC-024 related to accurate relay settings to allow out of bounds operations related to frequency and voltage deviations.
Response: Under certain system conditions the response of frequency sensitive load to a frequency excursion may be sufficient to arrest and stabilize frequency following an event. The eastern interconnection may also demonstrate greater stability as compared to the other interconnections. However, frequency stability is not assured to be achieved in this manner for all system conditions, even for the eastern interconnection irrespective of Frequency Bias setting accuracy. The intent of BAL-003 is independent of PRC-024 intent. Specifically the purpose of BAL-003 is to better match a Balancing Authority's Frequency Bias Setting to its Frequency Response Characteristic, which should also reduce the probability for UFLS activation. The purpose of PRC-024 is to ensure generation remains		

Organization	Yes or No	Question 4 Comment
connected during a tolerable frequency or voltage excursion. Furthermore, consideration of voltage deviations is outside the scope of the approved project.		
NIPSCO	No	Yes and no, similar to BAL-002 I think this should read "Each Balancing Authority or Reserve Sharing Group shall ....., With so many BA's I believe the RSGs will be play a big role in this compliance ... This comment applies to only R1,
Response: The SDT has revised Requirement R1 to reference Reserve Sharing Groups.		
NorthWestern Energy	No	A Balancing Authority's frequency response is based upon a "median" value calculated from analyzing multiple events. Frequency response during some of these events is better than others, depending on the system conditions at the time and the amount system loading and unloaded generation online at the time of the event. Given these circumstances a BA's actual response could vary by event (better or worse than median), thus compliance measurement per event to a frequency response obligation based on the median response (over multiple events) could put BA's in non-compliant situations unjustly.
Response: The SDT agrees that compliance should not be based on an individual event but based on a series of events.		
Energy Mark, Inc.	No	Comment 9: I agree that each BA should be required to provide a minimum level of Frequency Response to provide for its share of the total Frequency Response required for interconnection reliability. Comment 10: I also agree with the methods used to measure SEFRD subject to my comments on FRS Form 1. Comment 11: I do not agree that the method suggested for setting the FRO will achieve the desired goal of maintaining interconnection reliability. The measurement method offered only evaluates the supply of Frequency Response. It does not evaluate the demand (need) for Frequency Response. Since frequency error is the difference between the demand and supply any effective measure for maintaining reliability due to frequency error must include both the demand and supply parts of this balance. As a consequence, the method will be blind to changes (good or bad) in the demand for Frequency Response. Changes in the demand for Frequency Response will require subsequent changes in the supply for Frequency Response that this standard fails to address until the following year and leaves the interconnection at risk for unreliable operation. Comment 12: The requirements associated with Frequency Response as defined in this standard will not assure interconnection reliability. Frequency Response is a two part service. The first part of this service is the rate at which energy is supplied in proportion to frequency error. This first part is commonly represented as the Frequency Response and the corresponding Frequency Bias Setting. The second part of the service is the amount of capacity that the BA stands ready to supply at this stated proportion in response to frequency error. Failure to effectively specify and measure the amount of capacity that the BA stands ready to supply at the stated proportion could put the interconnection at reliability risk when the required amount of capacity is

Organization	Yes or No	Question 4 Comment
		not included in the operating plan.
Response: Comment 11 - The FRO provides a target for ensuring robust frequency response is achieved by all Balancing Authorities. Both FRO and FRM values are considered by the algorithm determining the Frequency Bias Setting for the next year. While there is mutual dependence between supply and demand with respect to frequency response, the resultant frequency deviation is more important than the cause as it is the effect on system operations realized that determines the magnitude of control response required for reliability. It is expected robust frequency control will yield smaller frequency deviations during events and in turn require less incremental control response than currently realized for maintaining frequency. Comment 12 – Capacity is an important yet independent consideration. First, responsive robust control is necessary. Next, the Frequency Bias Setting must better approximate the Frequency Response Characteristic for improved control response. Adequate capacity is an implicit assumption for reliable grid operation.		
Hydro-Quebec TransEnergie	No	The proposed method is good to measure frequency response at point "B". However, point "C" is not taken in consideration in this measure. As for the FRO, a N-2 criteria is more stringent for an Interconnection with less units than a large Interconnection. The risk associated with coincidental events is much higher in a large Interconnection. For this reason, we believe that N-1 criteria should be considered for a small Interconnection like Quebec.
Response: The SDT agrees that the size of an Interconnection can make a difference in Frequency Response. This standard is intended to apply to all Interconnections. The SDT has modified the definition for FRO. The definition now reads "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection." A smaller Interconnection can and should request a variance if needed.		
Westar Energy	No	The lagging measure is a concern. The ERO should be required to provide an updated proposed/possible list of frequency events monthly so BA's can determine their FRM through out the year so corrective action can be taken if needed.Prior year events should be excluded (just to get to 25 events). This could result in begin non-compliant twice for the same events.
Response: The SDT recommends posting selected events quarterly to give BAs time to evaluate their compliance. The SDT has evaluated the method for assessing compliance and has determined compliance is best demonstrated on a quarterly basis using a rolling 12 months data period.		
FMPP	No	The proposed Requirement 1 states: Each Balancing Authority shall achieve a Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO).Attachment A states that if a year occurs in which there are not 25 events that meet the remaining criteria below, then the most recent 25 events (as defined below) will be used for determination of an entity's compliance with the FRM requirement and storage of SEFRD. Problem - by using events from last year to determine an entity's compliance with a Requirement for this year puts the entity in double jeopardy for last year's events, which were already used for compliance for last year.

Organization	Yes or No	Question 4 Comment
Response: The SDT recommends posting selected events quarterly to give BAs time to evaluate their compliance. The SDT has evaluated the method for assessing compliance and has determined compliance is best demonstrated on a quarterly basis using a rolling 12 months data period.		
EKPC	No	The method for measurement is not detailed. Also, the method indicates a lagging indicator. Hows is the BA to ensure its compliance through the year?
Response: FRS Form 1 now details the measurement method. An entity can use the Criteria for Selecting Events to confirm compliance during the year. The SDT recommends posting selected events quarterly to give BAs time to evaluate their compliance.		
ISO New Engand Inc.	No	We have a difficulty seeing the BA being the only entity held responsible for maintaining interconnection frequency and arresting frequency deviations. When there is a sudden and sizable change to system resource or demand, the first response to a frequency deviation caused by this change would be the generators' governors. This will provide a mitigating effect for the immediate seconds up to minutes. The frequency bias setting will then kick in to supplement the mitigation need. The governors are owned by the Generator Owners; the BAs do not own these facilities and hence can do little to address frequency response during this initial period.
Response: While the SDT has described possible methods for obtaining Frequency Response compliance with this standard, the SDT is not prescribing a particular method for entities to implement. Governor operation is outside the scope of the approved project SAR. Any entity may submit a SAR request to modify or create a standard.		
American Electric Power	No	Between the definition and the requirement in Attachment A, it is unclear if FRM is a reliability-supported, performance-based measure, or instead, if it is a calculated number based on previous performance. As written, it is unclear if this is a performance-based requirement, or simply a calculation that should be utilized in some way. In any event, the requirement needs to be re-written to clarify its intent.
Response: The SDT has modified the definition of FRM to read "The median of all the Frequency Response observations reported annually on FRS Form 1."		
Duke Energy	No	Duke Energy agrees that a BA should be required to achieve a minimum level of Frequency Response, however Duke Energy believes the method for measurement needs improvement - please see comments to 1 and 2 above.Duke Energy agrees with the concept that a Balancing Authority should be required to achieve a minimum level of Frequency Response however the method for measurement should also allow exclusion of certain events, such as when the frequency deviation is associated with the BA's contingent loss of generation, or when an event is coincident with a significant change in ramped interchange. It is not clear how the FRO will be determined - Duke Energy believes that the industry should agree on the methodology which would be used for the ERO to determine the response desired for the Interconnection and

Organization	Yes or No	Question 4 Comment
		how the allocation for the FRO would be determined for each Balancing Authority. The calculation of FRO allocation (in Attachment 1) is not clear on whether the peak load and generation data used is historic data or forecasted data. It is also not clear how the assignment of the FRO would accommodate a mid-year change in Balancing Authority size or other attribute that could change the calculated response. Duke Energy questions if a BA providing better response than its allocated FRO in any year should be held to achieving that in the following year - Duke Energy believes that should be the decision of the BA if it chooses to achieve more than the minimum requirement applied to others.
Response: The FRS Form 1 has been modified to allow for adjustments (not exclusions) to the load and generation. The Industry will agree on the methodology for determining the FRO by submitting approval ballots on the standard. The SDT recognizes the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and describe the calculation methodology utilized. The second document will explain the rationale for the requirements as supplemental standard information. The FR SDT agrees that mid-year changes need to be addressed and will review this issue during the field trial. A BA's FRO is not based on the previous year's compliance. FRO is determined using the methodology described in Attachment A.		
Patterson Consulting, Inc.	No	Requiring a Balancing Authority to provide Frequency Response and measuring that Frequency Response consistently, is critical to maintaining reliability. The requirement is long overdue and the concept is a good one. The method for measurement in FRS Form 1 is not consistent with the definition of FRM. The desired "averaging" of input data over specific time ranges by the Balancing Authority as it completes FRS Form 1 appears only in the background and instructions for FRS Form 1. Since this "instruction" document will not be a part of the standard, it is not obvious that Balancing Authority's will be compelled to provide consistent data. Therefore, the standard will fail to achieve the stated purpose of providing "...consistent methods for measuring Frequency Response...". Attachment A, other than the section providing guidance regarding event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but should not be requirements. Attachment A should include only the event selection process and calculations associated with requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" are included in Attachment A, they should be moved to the standard. FRS Form 1 should be an attachment to the standard as this form contains and performs the required calculations. The remaining information in Attachment A should become either a standalone (technical) document, or be combined with information such as "FRS Form 1 Background and Instructions" and renamed. As further clarification regarding the ambiguity identified in the previous paragraph, Attachment A

Organization	Yes or No	Question 4 Comment
		could be interpreted as additional requirements on the Balancing Authority, ERO, or both. The language and scope is not sufficiently clear to identify whether statements are informative or requirements. This lack of clarity makes it impossible for entities to identify requirements, acquire appropriate tools and resources related to requirements, and to provide suitable performance to meet requirements. For example, the statement "A final listing of official events to be used in the calculation will be available from NERC by December 10 each year." may be intended as a requirement rather than a statement suggesting a typical schedule. Further, if the previous statement is a typical schedule, then the statement "The ERO will use the following criteria for the selection of events to be analyzed." could be interpreted as merely the typical process to be used, but not a binding one.
Response: The SDT has modified FRS Form 1 to allow for adjustments. The SDT has modified the Attachment A documentation to clarify the calculation methodology. The SDT has modified the Requirements and added measures to clarify how an entity is to show compliance.		
Alberta Electric System Operator	Yes	The AESO agrees that there should be certain minimum requirement(s) of Frequency Response. In Attachment A, it mentioned that it will be based on the protection criteria and Point C, and the FRM is determined based on the settled deviation. The AESO suggests that the SDT describe how the FRM be related with the FRO as they are determined by different time frames. The AESO suggests NERC investigate the measure and method of separate FRM / FRO for different time frames, or provide technical evidence that the proposed FRM / FRO can also address the technical concerns in different time frames.
Response: The FRO is a determined value providing a target for ensuring robust frequency response is achieved by all Balancing Authorities. The FRM is the medium value of observations for the time period. The intent is for FRM to always be equal or more negative than the FRO, signifying robust control resulting in proper frequency response. As such, the determination timeframes does not have to be the same for each value.		
Independent Electricity System Operator	Yes	We agree with the BA being one of the responsible entities to achieve a minimum level of FR, and the method of measurement. However, R1 does not correspond to the figures shown in the FRS (Form 1) in that the FRM (the median) is -14.5 whereas the FRO is -15.8. The FRO is more negative than the FRM, which does not seem to correspond to what's stipulated in R1 (FRM to be equal or more negative than its FRO).
Response: FRS Form 1 has been modified to correct calculations and to allow for adjustments (not exclusions) to the load and generation.		
Arizona Public Service Company	Yes	What is meant by discretely administered determination, under the heading "Frequency Obligation and Allocation" of Attachment A? Please explain.
Response: The SDT has provided an administrative procedure for the ERO to follow in Attachment A.		

Organization	Yes or No	Question 4 Comment
ENBALA Power Networks	Yes	ENBALA does believe that a BA should be responsible for a minimum level of Frequency Response as calculated on Form 1 and reflected in its FRO. Furthermore, we feel that additional data collected on the frequency nadir, such as the metric suggested in the recent Lawrence Berkeley National Laboratory of nadir-based frequency response, would be useful in assessing the current inertial response capabilities and level of risk for under-frequency load shedding.
Response: The FRO is a determined value providing a target for ensuring robust frequency response is achieved by all Balancing Authorities. The FRM is the medium value of observations for the time period. The intent is for FRM to always be equal or more negative than the FRO, signifying robust control resulting in proper frequency response. As such, the determination timeframes does not have to be the same for each value.		
Beacon Power Corporation	Yes	The concept of requiring each Balancing Authority to achieve some level of Frequency Response and calculate it consistently is appropriate and necessary.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
SPP Standards Development	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
Associated Electric Cooperative, Inc.	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		

5. ***Requirement 2 identifies when the Balancing Authority must implement its Frequency Bias Setting.***

R2. Each Balancing Authority shall implement the Frequency Bias Setting (fixed or variable) provided by the ERO into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effective coordinated secondary control, using the results from the calculation methodology detailed in Attachment A.

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

Summary Consideration: The majority of the commenters did not agree with the implementation plan specified in Requirement R2. Many of the comments received echo concerns raised in comments for question 4 such as the Attachment A calculation methodology is not clear; there was insufficient information provided to address the use of variable bias, and FRO determination was questionable. Several commenters were concerned with the role assigned to the ERO, questioning how the ERO will use the FRM to determine the required BA Frequency Bias Setting and if the ERO was the correct entity to perform this action. Commenters also expressed concerns with performing an FRM analysis at the end of the year over the holiday period, suggesting the implementation time should be increased from one month to two months. Some commenters also expressed concern that CPS and L10 compliance may be adversely affected by the requirements proposed for calculating the Frequency Bias Setting.

In response to the comments received from industry, the SDT has revised Attachment A to clarify the calculation methodology; revised Requirement R2 to clarify how an entity implements the Frequency Bias Setting provided by the ERO; and also modified FRS Form 1 to allow for adjustments. Regarding FRO determination, the SDT is using a deterministic approach and also evaluating a probabilistic method. With respect to ERO actions, the SDT is evaluating whether modifications to the NERC Rules of Procedure are necessary to ensure the ERO provides the necessary support. The SDT also will develop a second draft standard attachment, Attachment B, to define the methodology for lowering the minimum Frequency Bias Setting required, including maintaining a safety margin.

R2. Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias.

Organization	Yes or No	Question 5 Comment
Santee Cooper	No	It is not clear what the methodology (should be method) is in Attachment A. Is the frequency bias setting the BA's prior year FRM with a minimum value being a percentage of estimated yearly peak load or upcoming year maximum generation? What does "provided by the ERO" mean? Perhaps it should be verified or approved by the ERO (NERC).

Organization	Yes or No	Question 5 Comment
Response: Attachment A has been revised to clarify the calculation methodology. Requirement R2 has been revised for clarity and now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
LG&E and KU Energy	No	It is not clear what the methodology (should be method) is in Attachment A. Is the frequency bias setting the BA's prior year FRM with a minimum value being a percentage of estimated yearly peak load or upcoming year maximum generation? What does "provided by the ERO" mean? Perhaps it should be verified or approved by the ERO (NERC).
Response: Attachment A has been revised to clarify the calculation methodology. Requirement R2 has been revised for clarity and now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
SERC OC Standards Review Group	No	It is not clear what the methodology (should be method) is in Attachment A. Is the frequency bias setting the BA's prior year FRM with a minimum value being a percentage of estimated yearly peak load or upcoming year maximum generation? What does "provided by the ERO" mean? Perhaps it should be verified or approved by the ERO (NERC).
Response: Attachment A has been revised to clarify the calculation methodology. Requirement R2 has been revised for clarity and now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
South Carolina Electric and Gas	No	It is not clear what the methodology (should be method) is in Attachment A. Is the frequency bias setting the BA's prior year FRM with a minimum value being a percentage of estimated yearly peak load or upcoming year maximum generation? What does "provided by the ERO" mean? Perhaps it should be verified or approved by the ERO (NERC). We suggest defining the date as by the end of the first business day following the deadline for Frequency Bias Setting implementation.
Response: Attachment A has been revised to clarify the calculation methodology. Requirement R2 has been revised for clarity and now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure		

Organization	Yes or No	Question 5 Comment
effectively coordinated Tie Line Bias control." The SDT does not believe the suggestion to define the date is necessary since there is language in the standard stating the ERO will allow sufficient time to implement the Frequency Bias Setting.		
MRO's NERC Standards Review Subcommittee	No	Flexibility established in the date is better than the existing currently defined date in the standards. It is better to allow the ERO to specify the date to allow some flexibility in implementation. It appears that the responsible for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting. Frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to overbias than underbias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for frequency bias setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the frequency bias setting to ensure that the bias setting is overbiased.
Response: The SDT has modified the language in Requirement R2 to provide further clarity. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT agrees that over-bias is better than under-bias and has added Attachment B to define the methodology to lower the minimum Frequency Bias Setting and provide a safety margin.		
Midwest ISO Standards Collaborators	No	Flexibility established in the date is better than the existing currently defined date in the standards. It is better to allow the ERO to specify the date to allow some flexibility in implementation. It appears that the responsible for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting. Frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to overbias than underbias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for frequency bias setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the frequency bias setting to ensure that the bias setting is overbiased.
Response: The SDT has modified the language in Requirement R2 to provide further clarity. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT agrees that over-bias is better than under-bias and has added Attachment B to define the methodology to lower the minimum Frequency Bias Setting		

Organization	Yes or No	Question 5 Comment
and provide a safety margin.		
We Energies	No	Flexibility established in the date is better than the existing currently defined date in the standards. It is better to allow the ERO to specify the date to allow some flexibility in implementation. It appears that the responsibility for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting. Frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to over-bias than under-bias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for frequency bias setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the frequency bias setting to ensure that the bias setting is over-biased.
Response: The SDT has modified the language in Requirement R2 to provide further clarity. The Requirement now reads “Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control.” The SDT agrees that over-bias is better than under-bias and has added Attachment B to define the methodology to lower the minimum Frequency Bias Setting and provide a safety margin.		
FirstEnergy	No	We cannot agree at this time since Attachment A of the materials posted do not include sufficient details regarding the calculations used. Furthermore, there is no obligation imposed on the ERO to provide neither a reasonable time frame for implementation of the Frequency Bias Setting nor a requirement for the ERO to follow the methodology detailed in Attachment A. The team should consider adding a requirement for the ERO or clarifying where this obligation is covered in NERC’s Rules of Procedure.
Response: Attachment A has been revised to clarify the calculation methodology. The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary.		
Bonneville Power Administration	No	R2 - BPA believes that the ERO should not be providing the BA the Frequency Bias Settings for the BA. R2 points to Attachment A as having the calculation methodology, but there is no methodology spelled out in Attachment A, there are simply data requirements, delta frequency that will be included in surveys, tools to be used, etc. The statement ‘natural frequency response’ is in Attachment A many times, but it is never spelled out. What is meant by this phrase. This differs dramatically depending on when the event occurs due to different generating patterns, different types of load (frequency responsive versus not frequency responsive), etc.

Organization	Yes or No	Question 5 Comment
		The methodology needs to spell out how this will be taken into account when calculating the correct frequency bias. Secondly, how would this be done for variable bias?
Response: Requirement R2 has been revised for clarity and now reads, “Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control.” Attachment A has been revised to clarify the calculation methodology. The SDT agrees that over-bias is better than under-bias and has added Attachment B to define the methodology to lower the minimum Frequency Bias Setting and provide a safety margin. Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions. The SDT will provide additional and sufficient direction related to variable bias after review of this issue during the field trial. The term “natural frequency response” is no longer in Attachment A but it is used in the new Background Document. The SDT believes that this term is describing the response for any individual event and if calculated the statistical summation of multiple events. This term is more a work of art and not science and therefore is not capitalized or defined.		
SPP Standards Development	No	We would suggest ending the sentence at the second ERO, deleting the phrase '...to ensure effective coordinated secondary control, using the results from the calculation methodology detailed in Attachment A.' This phrase is more of an explanation of why this is being done rather than a part of an actual requirement.
Response: The SDT believes this language provides additional clarity and should remain as is. The SDT has removed the reference to Attachment A.		
IRC Standards Review Committee	No	It is not clear how the ERO uses the FRM to determine the required Frequency Bias Settings. Please clarify. Also, it should not be necessary for the ERO to do the determination for all the Interconnections. There are already in place methods for this by the existing ERCOT and WECC Interconnections. The SRC suggests that the ERO may not be the appropriate technical entity. The ERO may be the appropriate entity to serve as the receiver of the forms and analyze results for the Eastern Interconnection, but existing processes are already in place elsewhere. It should be sufficient that those processes continue and submit copies of Form 1 to the ERO. This may also be appropriate for Hydro Quebec. In addition, whichever entity determines the Frequency Bias Setting must provide implementation time for the BAs to implement the settings. The proposed language says only that the BA shall implement it on the date specified, but it doesn’t address the need for that date to include some implementation time.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to clarify the		

Organization	Yes or No	Question 5 Comment
role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT disagrees that the standard should independently address each Interconnection, and believes it is necessary to have a common methodology applicable to each Interconnection. An entity can request a variance and justify why deviation from the methodology adopted is necessary. The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will also define implementation timing.		
ERCOT	No	It is not clear how the ERO uses the FRM to determine the required Frequency Bias Settings. It should not be necessary for the ERO to do the determination for all the Interconnections. There are already in place methods for this by the existing ERCOT and WECC Interconnections. The SRC suggests that the ERO may not be the appropriate technical entity. The ERO may be the appropriate entity to serve as the receiver of the forms and analyze results for the Eastern Interconnection, but existing processes are already in place elsewhere. It should be sufficient that those processes continue and submit copies of Form 1 to the ERO. This may also be appropriate for Hydro Quebec. In addition, whichever entity determines the Frequency Bias Setting must provide implementation time for the BAs to implement the settings. The proposed language says only that the BA shall implement it on the date specified, but it doesn't address the need for that date to include some implementation time.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to clarify the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT disagrees that the standard should independently address each Interconnection, and believes it is necessary to have a common methodology applicable to each Interconnection. An entity can request a variance and justify why deviation from the methodology adopted is necessary. The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will also define implementation timing.		
Kansas City Power & Light	No	The Frequency Response Obligation determination for the interconnection as described in Attachment A is a crude method and will result in obligations that will exceed the FRO that is intended. This will result in additional cost to BA's that is unnecessary to achieve the purpose of maintaining sufficient generation online to arrest frequency degradation events caused by loss of generating resources. The current NERC method for calculating a BA's actual frequency response are inaccurate and provide misleading guidance in the actual frequency response of a BA. These methods need considerable improvement before any attempts to hold a BA to an expected level of frequency response as this proposal

Organization	Yes or No	Question 5 Comment
		has stated.
Response: The minimum level of response selected for the field trial uses a deterministic approach. The actual level of response specified in the final version of the draft standard may be based on analysis of data obtained from the field trial. The SDT is also evaluating a probabilistic method to determine the FRO. FRS Form 1 has been modified to correctly calculate Frequency Response.		
Southern Company	No	Comments: Comment 2: BAL-003-1, Requirement R2. The requirement should be made less prescriptive by removing references to the calculation methodology and Attachment A. The responsible entity should understand the fundamental and basic requirement - to implement the Frequency Bias Setting into its Areas Control Error calculation. Proposed language is as follows: Each Balancing Authority shall implement the Frequency Bias Setting (fixed or variable) provided by the ERO into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effective coordinated secondary control. Comment 3: BAL-003-1, Requirement R2 and Section 1.4 Additional Compliance Information. The SDT should consider whether or not the ERO has compliance obligations pursuant to the obligations mentioned in the proposed Standard. Requirement R2, states that the ERO should provide the BA with the Frequency Bias Setting and the specified date to begin the calculation. The R1 Supplemental Information section states that the ERO is obligated to post the official list of events. The R2 Supplemental Information section states that the ERO is obligated to validate the FRM and Frequency Bias Settings and disseminate the Frequency Bias Settings Report along with the implementation date. These obligations should be confirmed and properly incorporated into Standard if appropriate.
Response: The SDT disagrees that the standard should independently address each Interconnection, and believes it is necessary to have a common methodology applicable to each Interconnection. An entity can request a variance and justify why deviation from the methodology adopted is necessary. The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will also define implementation timing.		
Energy Mark, Inc.	No	Comment 13: I agree that the BA shall implement the Frequency Bias Setting provided by the ERO into it Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effective coordinated secondary control. Comment 14: I do not agree that the results from the calculation methodology detailed in Attachment A will provide the correct Frequency Bias Setting. My comments on the calculation methodology are included elsewhere in my comments on Attachment A and FRS Form 1.
Response: Comment 13 – The SDT thanks you for your affirmative comment. Note that based on comments from other stakeholders, the language in Requirement R2 was modified to state, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) "validated" by the ERO, into its Area Control Error (ACE) calculation . . ."		

Organization	Yes or No	Question 5 Comment
Comment 14 - Please see the SDT response to your Attachment A and FRS Form 1 comments.		
EKPC	No	The method is not clear in Attachment A.
Response: Attachment A has been revised to clarify the calculation methodology.		
Seattle City Light	No	Currently a Balancing Authority has only about one month over holiday periods(December 10 to January 10) to assemble its data and calculate the Frequency Response Measure (FRM). Further, Attachment A requires the ERO to use at least 25 events for the calculation of FRM. Seattle City Light (SCL) believes that one month is insufficient time given the number of events required. So SCL recommends additional time, such as two months or to reduce the number of events to be included in annual reviews.
Response: The SDT recommends posting the selected events on a quarterly basis which should provide ample time for BAs to provide the information.		
American Electric Power	No	It appears this standard deviates from past practice for calculating frequency bias. It is unclear how this might affect the CPS Bounds L10 calculation.
Response: The Frequency Bias Setting calculation remains the same. The SDT is only modifying the "minimum Frequency Bias Setting" threshold. The SDT understands reducing the minimum Frequency Bias Setting will affect L10 and ACE values which is why the SDT proposes monitoring these parameters and undoing the modification if adverse results are realized.		
Duke Energy	No	Duke Energy believes that this needs to be restated. Will the ERO perform the calculations to determine each BA's Bias? Will the ERO provide ample time between publication of the settings and the date of implementation? If effective coordinated secondary control is desired, other related operational parameters (e.g., L10) need to be set at the same time. Since measurement and reporting of operational performance is primarily on a monthly basis (e.g., CPS1/CPS2), the implementation date should be on or near the first of a month, but during normal working hours (so that adequate support personnel are available).
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to clarify the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will		

Organization	Yes or No	Question 5 Comment
also define implementation timing. The SDT understands reducing the minimum Frequency Bias Setting will affect L10 and ACE values which is why the SDT proposes monitoring these parameters and undoing the modification if adverse results are realized. The SDT is not proposing to change the methodology presently used to set the timing of the implementation of the Frequency Bias Setting.		
Patterson Consulting, Inc.	No	The concept of requiring a Balancing Authority to implement its Frequency Bias Setting at a specific time and using a specific calculation is meaningful. This requirement is not clearly worded, however. If the intent of Requirement 2 is to identify "...when the Balancing Authority must implement its Frequency Bias Setting..." the requirement should stop after "...on the date specified by the ERO." The remaining portion of the requirement explains the need for the requirement and should be moved to supporting material. Attachment A does not have a "calculation methodology" associated with the Frequency Bias Setting unless the language describing historical practice and the benefits of moving a Frequency Bias Setting closer to a Balancing Authority's natural Frequency Response are intended to constitute a "calculation methodology." FRS Form 1 has the "calculation methodology" of using the minimum (since the value is negative) of last year's FRM, next year's FRO, and percentage of next year's peak load or generation. Attachment A does not mention this methodology and the requirement does not mention FRS Form 1. The clause "..., using the results from the calculation methodology detailed in Attachment A." appears to place an obscure requirement on the ERO since the ERO is the entity providing the Frequency Bias Setting to be implemented by the Balancing Authority. If the ERO is intended to use the value from FRS Form 1, after verifying data and calculations, then state that expectation explicitly and clearly. Otherwise, the ERO could set Frequency Bias Settings in another manner after observing the Form 1 values. The requirement for the ERO to provide a Frequency Bias Setting to each Balancing Authority begs the question of how variable bias will be implemented. Historically, the Balancing Authority implements its algorithm with oversight from NERC (Resources Subcommittee). The manner and expectation for providing data and algorithms related to variable bias are inadequate.
Response: The SDT has modified the language in Requirement R2 to clarify the role of the ERO. The Requirement now reads “Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control.” The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will also define implementation timing. Attachment A has been revised to clarify the calculation methodology. FRS Form 1 has been modified to correctly calculate Frequency Response and to allow for adjustments (not exclusions) to the load and generation. Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions. The SDT will provide		

Organization	Yes or No	Question 5 Comment
additional and sufficient direction related to variable bias after review of this issue during the field trial.		
Alberta Electric System Operator	Yes	The AESO suggests that the standard should provide a description on how the ERO would determine the frequency bias setting and the relation to the FRO.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to clarify the role of the ERO. The Requirement now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT is evaluating if a modification to the NERC Rules of Procedure to obligate the ERO to perform the tasks identified in the standard is necessary and will also define implementation timing.		
NIPSCO	Yes	I guess the ERO will calculate the Bias, interesting.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to clarify the role of the ERO. The Requirement now reads, "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
Manitoba Hydro	Yes	The implementation schedule seems reasonable.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Westar Energy	Yes	
FMPP	Yes	
Progress Energy	Yes	
ENBALA Power Networks	Yes	
NorthWestern Energy	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 5 Comment
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		

6. ***Requirement 3 mandates that a Balancing Authority operate its Automatic Generation Control (AGC) on Tie Line Bias unless it becomes adverse to the integrity of its system.***

R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Bias, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area.

Do you agree that a Balancing Authority should operate its AGC on Tie Line Bias unless it becomes adverse to its system? If not, please explain in the comment area below.

Summary Consideration: Approximately half of the comments received agreed that a Balancing Authority should operate its AGC in Tie Line Bias unless an Adverse Reliability Impact occurs. Many of the dissenters were concerned with the apparent conflict with BAL-005.1b Requirement R6, efforts of the Balancing Authority Reliability-based Controls (BARC) SDT with modifying BAL-005, and concern that the draft standard should not dictate an AGC operating control mode. Other commenters indicated the language of Requirement R3 needed to be revised for clarity and that the requirement could place a reporting burden on the Balancing Authorities. It was also noted that a single BA Interconnection does not operate AGC using Tie Line Bias mode.

In response to industry comments received, the SDT has revised Requirement R3 by adding Overlap Regulation Service language and allowing the AGC operating mode to be changed for an Adverse Reliability Impact.

R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area.

Organization	Yes or No	Question 6 Comment
Santee Cooper	No	BAL-003-0, Requirement 3 requires operation of AGC on Tie Line Frequency Bias. BAL-005-0.1b, Requirement 6 requires the BA to compare total Net Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. We suggest that Requirement 3 be restated to "shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless ...."Tie Line bias is the (Ia-Is) term and frequency bias is the -10B(Fa-Fs) term.
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		

Organization	Yes or No	Question 6 Comment
LG&E and KU Energy	No	BAL-003-0, Requirement 3 requires operation of AGC on Tie Line Frequency Bias. BAL-005-0.1b, Requirement 6 requires the BA to compare total Net Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE.We suggest that Requirement 3 be restated to "shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless ...."Tie Line bias is the (Ia-Is) term and frequency bias is the -10B(Fa-Fs) term. This should be coordinated with BARCSDT modifications to BAL-005.
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area." This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		
SERC OC Standards Review Group	No	BAL-003-0, Requirement 3 requires operation of AGC on Tie Line Frequency Bias. BAL-005-0.1b, Requirement 6 requires the BA to compare total Net Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE.We suggest that Requirement 3 be restated to "shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless ...."Tie Line bias is the (Ia-Is) term and frequency bias is the -10B(Fa-Fs) term. This should be coordinated with BARCSDT modifications to BAL-005.
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area." This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		
South Carolina Electric and Gas	No	BAL-003-0, Requirement 3 requires operation of AGC on Tie Line Frequency Bias. BAL-005-0.1b, Requirement 6 requires the BA to compare total Net Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE.We suggest that Requirement 3 be restated to "shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless ...."Tie Line bias is the (Ia-Is) term and frequency bias is the -10B(Fa-Fs) term. This should be coordinated with BARCSDT modifications to BAL-005.
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability		

Organization	Yes or No	Question 6 Comment
Impact on the Balancing Authority's Area." This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		
Bonneville Power Administration	No	R3. BPA does not believe this standard should dictate the control mode for AGC. That is better suited to be in BAL-001 and should not be repeated in this standard - the ACE used for reporting is spelled out in BAL-001 R1 and is also discussed in BAL-005 R6. R3 should be removed from this standard, not modified to fit with what is stated in BAL-001 or BAL-005.
Response: This standard is proposed to go into effect prior to implementation of the BARC draft standard. A determination of which reliability standard should specify the AGC control mode used for system operations can be made once development of the BARC draft standard is completed. Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
IRC Standards Review Committee	No	Single BA Interconnections do not operate on Tie Line Bias. The requirement should be modified to accommodate this or regional variances should be written by the SDT to address existing differences. In addition this requirement, as written, does not provide for momentary cessation of AGC for any reason, nor for reasonable system maintenance, repair, or updates. As written, it seems to say that any duration of operation off Tie Line Bias is unacceptable and, thus, would be a violation.
Response: The SDT agrees that a single BA Interconnection does not operate using Tie Line Bias mode. The "Additional Compliance Information" section has been revised to clarify this situation. The SDT disagrees that the Requirement does not allow for instances of not operating in Tie Line Bias mode. The revised Requirement states "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
ISO New Engand Inc.	No	Single BA Interconnections do not operate on Tie Line Bias. The requirement should be modified to accommodate this or regional variances should be written by the SDT to address existing differences. In addition this requirement, as written, does not provide for momentary cessation of AGC for any reason, nor for reasonable system maintenance, repair, or updates. As written, it seems to say that any duration of operation off Tie Line Bias is unacceptable and, thus, would be a violation.
Response: The SDT agrees that a single BA Interconnection does not operate using Tie Line Bias mode. The "Additional Compliance Information" section has been revised to clarify this situation.		

Organization	Yes or No	Question 6 Comment
The SDT disagrees that the Requirement does not allow for instances of not operating in Tie Line Bias mode. The revised Requirement states "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
ERCOT	No	Single BA Interconnections do not operate on Tie Line Bias. The requirement should be modified to accommodate this or regional variances should be written by the SDT to address existing differences. In addition this requirement, as written, does not provide for momentary cessation of AGC for any reason, nor for reasonable system maintenance, repair, or updates. As written, it seems to say that any duration of operation off Tie Line Bias is unacceptable and, thus, would be a violation.
Response: The SDT agrees that a single BA Interconnection does not operate using Tie Line Bias mode. The "Additional Compliance Information" section has been revised to clarify this situation. The SDT disagrees that the Requirement does not allow for instances of not operating in Tie Line Bias mode. The revised Requirement states "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
Kansas City Power & Light	No	The impact of operating in an inappropriate AGC control mode is bigger than the BA's own balancing area. The control of the area affects other BA's around a BA and if enough BA's are involved, can affect an interconnection. Recommend the requirement be modified to consider the reliability impact on its own balancing area, the balancing areas of adjacent BA's and the interconnection.
Response: The SDT agrees and has modified Requirement R3 to read, "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
Southern Company	No	Comments: Agree only to the extent that an accurate frequency measurement is available to the BA. If not frequency measurement is available, then that should be considered an adverse condition and thus TLB is not appropriate. In other words, one small BA maintaining TLB may not cause the condition in the Glossary definition of Adverse Reliability Impact but it is still not appropriate for them to stay on TLB.
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area." This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		

Organization	Yes or No	Question 6 Comment
NIPSCO	No	Yes, It was proposed that AGC be replaced by Automatic Resource Control (ARC) in the standards but did not pass. The SDT may want to monitor this related effort.
Response: The SDT is using approved definitions listed in the NERC Glossary of Terms. Changes to current NERC Glossary of Terms definition language not used in this standard would need to occur as a separate project.		
Energy Mark, Inc.	No	Comment 15: Requirement 3 as written is unenforceable because it is too difficult to define “unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.” Comment 16: What if operation out of Tie line Bias control does not have an Adverse Reliability Impact on the Balancing Authority’s Area, but does have an Adverse Reliability Impact on another BA? Comment 17: A document follows that provides an initial starting justification for the elimination of this Requirement. See following “Requirements for AGC Operation, January 25, 2011.”Requirements for AGC Operation, January 25, 2011 Introduction:As of the date of these comments there are two requirements in the NERC Standards that address the operation of AGC. • The first is in BAL-003-0.1b - Frequency Response and Bias, Requirement R3.R3. Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability. • The second is in BAL-005-0.1b - Automatic Generation Control, Requirement R7.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. These requirements are misdirected and, for compliance purposes, they are difficult to measure effectively. This paper provides the technical basis for replacing these requirements with new requirements that will not only achieve the intent of these requirements, but do so in a more effective and measurable manner. Background: Automatic Generation Control (AGC) is a computer control system contained in the Control Center EMS that performs a number of critical functions related to the balancing function necessary to maintain frequency and associated reliability. Among the functions it performs are: 1) the collection of telemetered and local data useful for determining the appropriate control actions, 2) the calculation of Area Control Error (ACE), 3) determination of desired control actions that should be sent to those resources available for automatic dispatch, and

Organization	Yes or No	Question 6 Comment
		4) sending the actual control signals to implement that dispatch. Most AGC Systems have three basic modes of operation, 1) Tie-line Frequency Bias, 2) Constant Net Interchange and 3) Constant Frequency. The ACE Equation is the basis for all three modes of operation. • In the Tie-line Frequency Bias mode, all of the ACE Equation is used as an input to control action determination. • In the Constant Net Interchange mode, only the Tie-line Error portion of the ACE Equation is used as an input to control action determination. The Constant Net Interchange mode would normally be used when there is no information available to indicate interconnection frequency. • In the Constant Frequency mode, only the Frequency Bias portion of the ACE Equation is used as an input to control action determination. The Constant Frequency mode of operation would be used when the Tie-line Error is known to be misleading, inaccurate or unavailable. It is also used when there are no tie-lines in service as in the case of a single BA interconnection or during islanded operation.AGC Systems have been used in the industry since before the development of digital computers. Initially AGC Systems did little more than send instructions to generators based on evaluation of the ACE Equation. They have become more sophisticated since their inception and implement greater complexity in their evaluations of appropriate dispatch actions to the point that they include forecasting, reliability and economics within their algorithms. Modern AGC Systems determine control actions based on the collection of much more data than is included in the ACE Equation. This additional data includes: short-term load forecasts and forecast error estimates as influenced by weather; individual non-conforming load forecasts and forecast error; forecast interchange transaction information; generating unit ramp and response rates; generating unit economic operating points including valve position; generating unit incremental economic costs including start-up and maintenance; Hydro unit river flow limits as related to the operation of other units on the same waterway; energy storage capabilities and available energy; Inadvertent Interchange energy account balances; time error; and current control performance scores. As AGC Systems have evolved, the control mode in which they are operating, Tie-line Frequency Bias, Constant Net Interchange, or Constant Frequency, provides less and less information about the control actions that they implement. In a modern AGC System the control mode provides little information about how control actions are being determined and implemented. In fact, only someone experienced in AGC programming and implementation would have the knowledge necessary to determine whether or not an AGC System is providing reasonable control actions or control actions consistent with Tie-line Frequency Bias Control. Even someone with the necessary experience observing the operation of a modern AGC System for

Organization	Yes or No	Question 6 Comment
		a short period of time will be incapable of determining whether or not that system is providing effective or adequate control. Therefore, neither of the two requirements is effectively enforceable from a practical point of view. Perspective:A couple of examples are offered to add perspective to the problem. Example 1:R3 includes the requirement, "Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability." There are three conditions when operation on Tie-line Frequency Bias control may be adverse to the system or Interconnection reliability. 1. The first is when the Tie-line Error data used in the ACE Equation is incorrect. The ACE Equation will be incorrect when there are errors in the Actual or Scheduled Tie-line flow values. This condition will occur when there is telemetry failure of one or more tie-lines, when there is an unidentified scheduling error, or when there is a separation that causes a tie-line metering point to be located on a separate island due to interconnection separation or islanding. Telemetry failure will be indicated by the quality bits associated with the Tie-line telemetry. If AGC is disabled to identify a scheduling error, there should be an operating log entry. If AGC is disabled because of a separation, there will also be a log entry. 2. The second is when the actual frequency is determined to be incorrect. If measured frequency is incorrect, this condition should be indicated by an operating log entry and transfer to the redundant frequency device to provide measured frequency. When the actual frequency fails, this condition will be indicated by the quality bits associated with the measured frequency value and transfer to the redundant frequency device to provide measured frequency. 3. The third is when operation of AGC would provide control different from the desired control to address some emergency condition in the BA or elsewhere on the interconnection. If the operation of AGC would be adverse to system or Interconnection reliability and is disabled for this reason, this condition should be indicated by an operating log entry.In all cases, there should be a record of the reason for the use of other than Tie-line Frequency Bias control and records indicating the reason for the use of other control modes. In all cases, other than the third indicated above, an error in the value of ACE is the reason for not using Tie-line Bias Control and the quality bits for ACE or ACE component data should provide a reasonable explanation for the condition. The third case occurs with such infrequency that there should be no need for a special rule to address this condition. Example 2:R7 includes the requirement, "...If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange." Cases have been observed of an AGC System that does not perform as well as the manual dispatch used when the AGC System is inoperative. If a BA has a CPS1 score of 120% when using AGC and a CPS1 score of 125% when performing manual dispatch, should that BA be penalized for not having its AGC continuously operating? What is the goal? Is the goal to operate on AGC regardless of the result or is the goal to operate in a manner

Organization	Yes or No	Question 6 Comment
		that provides the best measured control? Alternatives:Since these requirements are not effectively measurable or enforceable, can a requirement or requirements be written to provide an equivalent to the intent of the old requirements addressing AGC operation?The industry has three alternatives to address this issue: 1. Retain requirements that are directed at the AGC System understanding that they are effectively not measureable or enforceable. 2. Eliminate requirements that are directed at the AGC System with the understanding that they were not contributing to reliability. 3. Determine an alternative method to evaluate, measure and enforce a requirement that will achieve a goal similar to the goal originally intended by the implementation of the AGC System requirements. Elimination of the requirement is an appropriate solution. However, if it is determined that a replacement measure is required, then the solution to this problem lies with the third alternative above. Solution:There is already a requirement that effectively enforces the intent of the above requirements. Instead of requiring the BA to control in a particular manner, CPS1, BAAL and DCS require the BA to achieve specific results with their control actions. All three measures require the BA to calculate ACE using Tie-line Frequency Bias for determination of their Reporting ACE. The requirements specify that at least 50% of the data must be valid for the one-minute average data to be included in the measures. The requirements for redundant frequency measurement devices assure that the BA will have the actual frequency data available to perform the necessary calculations. The data retention requirements specify the data they must retain to demonstrate that their control achieved the stated goals. Finally, this approach is consistent with the White House Executive Order on Improving Regulation and Regulatory Review in Section 1(b)(4) stating that regulatory agencies must: “to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that the regulated entities must adopt;...”

Response: Comment 15 & 16: Requirement R3 has been revised for clarity and now reads “Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.”

This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.

Comment 17: The SDT recognizes that from a compliance perspective it can be difficult to ascertain if an Adverse Reliability Impact exists. Nonetheless, the SDT is very concerned with adversely affecting primary Frequency Response when operating without AGC. The SDT believes revised language using NERC glossary defined terms will support proper compliance enforcement. It is expected entities will provide an explanation each time AGC Tie Line Bias mode is not used for

Organization	Yes or No	Question 6 Comment
the compliance auditor to assess.		
EKPC	No	Tie line bias is calculated using (NAI-NSI) while frequency bias is -10B(FA-FS).
Response: Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area."		
Duke Energy	No	Duke Energy agrees to the simple statement posed in the question; however, the requirement goes beyond that by using a defined term, Adverse Reliability Impact, which has a relatively narrow focus on extreme conditions. If a single BA lost a significant amount of its tie-line telemetry or its frequency sources, cascading outages and/or grid separation would not necessarily be imminent but it would be imprudent to remain in Tie Line Bias mode. Go back to the original language for the requirement - "Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability."
Response: The SDT has revised Requirement R3 language and believes the use of NERC glossary defined terms in the Requirement provides necessary clarity for compliance.		
Patterson Consulting, Inc.	No	While this requirement is in the existing standard, it places a significant reporting burden on a Balancing Authority to demonstrate compliance during audits for little reliability gain. In addition for single Balancing Authority interconnections, operating in this AGC mode is functionally equivalent to operating in flat frequency mode. This may cause some interconnections to seek a variance, just to avoid compliance complications. Perhaps this requirement could be replaced with a requirement for Balancing Authorities to contribute to frequency performance as well as balance commitments and resources, or to calculate the ACE it uses to report in other standards in a specific manner. As written, it could be interpreted to create a violation when AGC suspends or is offline.
Response: The SDT has taken into consideration the reporting burden on the Balancing Authority to demonstrate compliance. It is expected that entities will provide an explanation each time AGC Tie Line Bias mode is not used for the compliance auditor to assess. The SDT agrees that a single BA Interconnection does not operate using Tie Line Bias mode. The "Additional Compliance Information" section has been revised to clarify this situation. Requirement R3 has been revised for clarity and now reads "Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area." This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC		

Organization	Yes or No	Question 6 Comment
standard will take into account the work completed on this standard.		
FirstEnergy	Yes	Although we mostly agree with the requirement, we believe it can be improved. We suggest that the team add wording in the requirement to allow for brief periods where meters or communication channels fail and trip the AGC off Tie Line Bias. In most areas, if merely one BA trips off bias it would not have an adverse affect on BES reliability and furthermore, the BA can take alternative measures for these periods such as manual AGC. We suggest the team add wording similar to the second sentence of requirement R7 of BAL-005 which states: “If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.”
Response: Requirement R3 has been revised for clarity and now reads “Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.” This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		
Arizona Public Service Company	Yes	As long as Appendix 1 interpretation remains in effect for WECC Auto Time Error Payback. WECC BAs operate in Tie-Line and Time.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Hydro-Quebec TransEnergie	Yes	However the “Tie Line Bias” AGC mode is not appropriate for a Single Balancing Authority operating in an Interconnection. HQT uses the Flat Frequency mode.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT agrees that a single BA Interconnection does not operate using Tie Line Bias mode. The “Additional Compliance Information” section has been revised to clarify this situation. Requirement R3 has been revised for clarity and now reads “Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area.” This standard is scheduled to be completed and filed with FERC prior to the BARC standard being completed. The SDT anticipates that work on the BARC standard will take into account the work completed on this standard.		
Beacon Power Corporation	Yes	As R3 has not significantly changed, will the Interpretation of Requirement 3 from BAL-003-0.1b still be applicable to BAL-003-1?

Organization	Yes or No	Question 6 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. When this standard is approved and implemented it will replace all previous standards and interpretations.		
Westar Energy	Yes	
FMPP	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
We Energies	Yes	
American Electric Power	Yes	
SPP Standards Development	Yes	
Midwest ISO Standards Collaborators	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Alberta Electric System Operator	Yes	
Independent Electricity System Operator	Yes	
NorthWestern Energy	Yes	
Progress Energy	Yes	
ENBALA Power Networks	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.

Organization	Yes or No	Question 6 Comment
Response: Please refer to our response to Question 17.		

7. *Do you agree with the proposed Implementation Plan for this standard? If not, please explain in the comment area.*

Summary Consideration: The majority of the comments received stated that they did not agree with the proposed implementation plan for this standard. The main concerns were that the implementation plan would take several years to fully implement, that adjustment to the Frequency Bias Setting could not occur without first modifying the existing BAL-003-0.1b standard, and a preference for aligning implementation plan effective dates with the regulatory approval date. Several commenters expressed concern regarding the accuracy and clarity of Attachment A and how field testing efforts integrated into the implementation plan. One commenter observed that it would be ideal for the standard to require the use of variable bias.

In response to industry comments the SDT has revised Attachment A for correctness and clarity; changed all references in the standard and associated documents for BAL-003 to read "BAL-003-0.1b"; and removed the table showing the annual reduction schedule for the minimum bias setting. The SDT has provided a revised plan for reducing the minimum Frequency Bias Setting - the ERO will monitor the results of the reductions and make necessary corrections. Details for the reduction plan have been provided as Attachment B to the standard.

Organization	Yes or No	Question 7 Comment
Santee Cooper	No	The implementation plan has specific dates for reducing the bias settings currently defined in Requirement 5 over several years. Perhaps these dates should not be specific but tied to months following regulatory approval. Attachment A should be modified to match what is in the proposed standard. The values currently shown as percent "of peak/0.1 Hz" should be changed to percent of estimated yearly peak demand per 0.1 Hz change. For BAs that do not serve native load, percent "of upcoming years maximum generation/0.1 Hz should be changed to percent of its estimated maximum generation level in the coming year/0.1 Hz change.
Response: The SDT believes that the affect reducing the minimum bias setting will have on frequency, including unintended consequences, will not be observable for meaningful analysis over a short-time interval which is why the implementation plan specifies reducing the bias setting on an annual basis. The SDT deleted the section of the Implementation Plan that referenced "of peak/0.1 Hz".		
LG&E and KU Energy	No	The implementation plan has specific dates for reducing the bias settings currently defined in Requirement 5 over several years. Perhaps these dates should not be specific but tied to months following regulatory approval. Attachment A should be modified to match what is in the proposed standard. The values currently shown as percent "of peak/0.1 Hz" should be changed to percent of estimated yearly peak demand per 0.1 Hz change. For BAs that do not serve native load, percent "of upcoming years maximum generation/0.1 Hz should be changed to percent of its estimated maximum generation level in the coming year/0.1 Hz change

Organization	Yes or No	Question 7 Comment
Response: The SDT believes that the affect reducing the minimum bias setting will have on frequency, including unintended consequences, will not be observable for meaningful analysis over a short-time interval. The SDT deleted the section of the Implementation Plan that referenced “of peak/0.1 Hz”.		
South Carolina Electric and Gas	No	The implementation plan has specific dates for reducing the bias settings currently defined in Requirement 5 over several years. Perhaps these dates should not be specific but tied to months following regulatory approval. Attachment A should be modified to match what is in the proposed standard. The values currently shown as percent “of peak/0.1 Hz” should be changed to percent of estimated yearly peak demand per 0.1 Hz change. For BAs that do not serve native load, percent “of upcoming years maximum generation/0.1 Hz should be changed to percent of its estimated maximum generation level in the coming year/0.1 Hz change.
Response: The SDT believes that the affect reducing the minimum bias setting will have on frequency, including unintended consequences, will not be observable for meaningful analysis over a short-time interval. The SDT deleted the section of the Implementation Plan that referenced “of peak/0.1 Hz”.		
MRO's NERC Standards Review Subcommittee	No	We agree with the plan to phase out BAL-003-0.1b R5 over a period of years rather than abruptly terminate it because it will take several years to assess the impact. We recommend a wording change to the implementation plan. Please change ‘BAL-003-0 Requirement 5 should be retired as outlined in the following table,” to “BAL-003-0.1b Requirement 5 should be phased out by reducing the minimum frequency bias setting per the table.”It is not clear if the minimum frequency bias setting can be modified without modifying the existing BAL-003-0.1b standard. Is this being accomplished through the field trial? The implementation plan makes no mention of a field trial. It should. Please change all BAL-003-0 to BAL-003-0.1b.
Response: The SDT did change all references in the implementation plan for BAL-003-1 to read “BAL-003-0.1b.” The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Midwest ISO Standards Collaborators	No	We agree with the plan to phase out BAL-003-0.1b R5 over a period of years rather than abruptly terminate it because it will take several years to assess the impact. We recommend a wording change to the implementation plan. Please change ‘BAL-003-0 Requirement 5 should be retired as outlined in the following table,” to “BAL-003-0.1b Requirement 5 should be phased out by reducing the minimum frequency bias setting per the table.”It is not clear if the minimum frequency bias setting can be modified without modifying the existing BAL-003-0.1b standard. Is this being accomplished through the field trial? The implementation

Organization	Yes or No	Question 7 Comment
		plan makes no mention of a field trial. It should. Please change all BAL-003-0 to BAL-003-0.1b.
Response: The SDT has changed all references in the implementation plan for BAL-003-1 to read "BAL-003-0.1b." The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
We Energies	No	We agree with the plan to phase out BAL-003-0.1b R5 over a period of years rather than abruptly terminate it because it will take several years to assess the impact. We recommend a wording change to the implementation plan. Please change 'BAL-003-0 Requirement 5 should be retired as outlined in the following table," to "BAL-003-0.1b Requirement 5 should be phased out by reducing the minimum frequency bias setting per the table."It is not clear if the minimum frequency bias setting can be modified without modifying the existing BAL-003-0.1b standard. Is this being accomplished through the field trial? The implementation plan makes no mention of a field trial. It should.Please change all BAL-003-0 to BAL-003-0.1b
Response: The SDT has changed all references in the implementation plan for BAL-003-1 to read "BAL-003-0.1b." The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
FirstEnergy	No	We believe that the implementation plan should include information regarding the field trial and how it fits in with the phase-in implementation. It appears as though the field trial is being conducted based on 2010 data and will be concluded upon completion of the development of the standard but we think this could be clarified. Furthermore, as stated in the process manual, a field test "should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results." The field test information posted is not clear on the implementation schedule of the field test as well as when and how periodic updates will be available.
Response: The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Bonneville Power Administration	No	From a compliance perspective, it is administratively very burdensome to have portions of two different versions of a standard applicable at the same time, as specified in the Implementation Plan for BAL-003-1.

Organization	Yes or No	Question 7 Comment
		This type of structure adds an additional layer of complexity to all parts of the compliance administration process, as necessary to distinguish between the separate versions of the standard. Rather than create and prolong this type of situation over a 4 year time period, BPA asks that BAL-003-0 be retired in its entirety and that the contents of BAL-003-1 be expanded to also include R5, as specified in BAL-003-0. This change resolves the identified issues while also ensuring that all requirements of BAL-005 are in effect, as originally intended. The Implementation Plan for BAL-003-1 also includes a proposal to modify the specified limiting percentage of Native Load on a sliding scale over a 4 year time period. BAL-003-3 R5, as approved, explicitly specifies 1% as a minimum value for monthly average Frequency Bias Setting. As such, changing this value results in a change in the requirement itself. Instead of being done through an Implementation Plan, these types of changes should be made as specific modifications to the requirement in question. To resolve this issue, BPA asks that the sliding scale specified for percentage of peak load specified in the Implementation Plan be incorporated directly into BAL-003-1 as a part of the specified text of R5. This change meets the intended goal of applying a sliding scale to this value over time while assuring that the underlying change is implemented as a change to the requirement through the Standards Development Process.
Response: The SDT has added the R5 Requirement back into the proposed standard. The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary correction. Please refer to Attachment B for reduction plan details.		
IRC Standards Review Committee	No	What is the technical basis for the phase-out schedule? Making the standard requirements effective earlier than the schedule shown could result in the unintended consequence of non-compliance enforcement for performance that is caused by the change rather than by the non-performance of the functional entity .Also, the effective dates given in the Implementation differ from those in the draft standard. Different requirement numbers are expressed in each. Some of the implementation steps (retiring R5 of BAL-003-0) presented in the implementation plan start as early as May 2011. We do not believe that the BAL-003-1 standard will be approved by the industry or the NERC BoT at that time and that does not even take into account regulatory approval (or 12 months after BoT adoption in those jurisdictions where no regulatory approval is required). How can a standard begins to phase out while the successor standard is not anywhere near becoming effective?If the SDT wants to propose a gradual replacement of the current R5, we would suggest that the phase-out steps be tied to the date that the standard becomes effective.
Response: The SDT has removed the table showing the reduction schedule for the minimum bias setting.		

Organization	Yes or No	Question 7 Comment
The SDT has corrected the mismatch between effective dates in the implementation plan and the standard. The SDT has added the R5 Requirement back into the proposed standard. The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
ERCOT	No	What is the technical basis for the phase-out schedule? Making the standard requirements effective earlier than the schedule shown could result in the unintended consequence of non-compliance enforcement for performance that is caused by the change rather than by the non-performance of the functional entity. Also, the effective dates given in the Implementation differ from those in the draft standard. Different requirement numbers are expressed in each. Some of the implementation steps (retiring R5 of BAL-003-0) presented in the implementation plan start as early as May 2011. We do not believe that the BAL-003-1 standard will be approved by the industry or the NERC BoT at that time and that does not even take into account regulatory approval (or 12 months after BoT adoption in those jurisdictions where no regulatory approval is required). How can a standard begins to phase out while the successor standard is not anywhere near becoming effective? If the SDT wants to propose a gradual replacement of the current R5, we would suggest that the phase-out steps be tied to the date that the standard becomes effective.
Response: The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT has corrected the mismatch between effective dates in the implementation plan and the standard. The SDT has added the R5 Requirement back into the proposed standard. The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Kansas City Power & Light	No	How can hard dates for the phasing out of the current R5 be in the implementation plan for a standard under development? The concept of phasing out R5 and phasing in R2 could be done, however, this would take considerable thought as to how to implement that. This current proposed implementation plan should be carefully reconsidered.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Progress Energy	No	We agree with the graduated implementation for the FRO portion of the standard, but feel NERC needs to loosen the minimum frequency bias requirement immediately so that it matches the newly required frequency response. There are also other areas within the EMS the besides BA's frequency bias that should be addressed such as secondary frequency response systems that should also be included in this standard. Additionally, if the industry was truly concerned with matching bias values to actual response, they would switch to variable frequency bias. Variable bias requires additional up front work along with general maintenance, but it truly is the best way to accurately bias the ACE equation.
Response: The SDT believes that gradually relaxing the present standard is the prudent way to proceed. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT has revised the plan for reducing the minimum Frequency Bias Setting and is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT agrees that use of a variable, non-linear bias setting is the best solution. We also agree with you that variable, non-linear bias setting would be a superior way to go.		
NIPSCO	No	"Effective Date" section at the top of the Standard does not match the Implementation plan; I think there is an R4 missing in the second part of 1.3 .In the implementation plan add RSG to "Compliance with the Standards" 5 year phase-in on removing the 1% is a good idea
Response: The SDT has corrected the errors noted. The SDT has revised the plan for reducing the minimum Frequency Bias Setting and is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Energy Mark, Inc.	No	Comment 18: The Proposed Effective Date in the implementation plan is inconsistent with the Effective Data in the Draft Standard. Comment 19: The completion of the implementation plan does not occur until 2015. This lengthy plan stems from a standard that only measures reliability annually and provides only an annual window for changing

Organization	Yes or No	Question 7 Comment
		parameters such as Minimum Frequency Response. Alternative methods that measure reliability more frequently could me implemented with a shorter implementation plan.
Response: The SDT has corrected the mismatch between effective dates in the implementation plan and the standard. The SDT believes that gradually relaxing the present standard is the prudent way to proceed. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT has revised the plan for reducing the minimum Frequency Bias Setting and is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Beacon Power Corporation	No	Why is it appropriate to delay implementation of this standard for over 12 months after applicable approval? This seems an unnecessary delay considering the intent to operate under a field test. Similarly, delaying implementation of R2 for over 2 years seems unnecessary. Based on the suggested schedule for measuring FRM and implementing Frequency Bias Settings, there may be rationale to implement the standard on the first calendar year following approval. However, delays beyond the beginning of the next calendar year should require conclusive justification.
Response: The SDT believes that the affect reducing the minimum bias setting will have on frequency, including unintended consequences, will not be observable for meaningful analysis over a short-time interval. The SDT has added the R5 Requirement back into the proposed standard. The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
EKPC	No	Specific dates should be tied to regulatory approval.
Response: The SDT has revised the plan for reducing the minimum Frequency Bias Setting. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		

Organization	Yes or No	Question 7 Comment
ISO New Engand Inc.	No	We do not agree that a meaningful Implementation Plan can be developed until such time as the data gathering/field testing is completed. Therefore, we believe this Standard may be premature.
Response: The SDT has added the R5 Requirement back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent.		
American Electric Power	No	It is unprecedented that an implementation plan would require following some (but not all) requirement(s) within multiple versions of the same standard. This would make following the standard very difficult. Having to piece together multiple documents into a coherent requirement would be very difficult to achieve. There needs to be a definitive start and stop date for each version, rather than a phase in and phase out across multiple versions. We disagree with setting preselected dates beginning months away. Timing should be driven by applicable regulatory approval, as opposed to dates which appear to be arbitrarily selected. Going from 100% of the load-based, frequency bias calculation to 0% is unclear without correlating it to something else being phased in over time.It is very hard to follow how BAL-003-0 R5 relates to BAL-003-1. More work needs to be done by the SDT to explain how these relate to one another.
Response: The SDT has added the R5 Requirement back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent. Attachment A has been revised for clarity. FRS Form 1 has been revised to correct calculation errors and allow for adjustments.		
Duke Energy	No	Duke Energy does not agree with having prescribed dates for the gradual reduction of the minimum Frequency Bias Setting, as the implementation may drive significant issues which could delay, or halt the implementation at a certain level. It is not clear what process would be used to give the “go-ahead” to move to

Organization	Yes or No	Question 7 Comment
		the next level (agree?).
Response: The SDT has added the R5 Requirement back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent.		
Patterson Consulting, Inc.	No	The implementation plan should address implementing these requirements at the same time for all Balancing Authorities within an interconnection, regardless of regulatory approvals. The present implementation plan will require some Balancing Authorities within an interconnection to operate to the new standard while other Balancing Authorities operate to the old standard if multiple regulatory jurisdictions exist as they do within two interconnections. This could lead to uncoordinated and unreliable operation within an interconnection.
Response: The SDT does not believe that staggered implementation will lead to uncoordinated and unreliable operation within an interconnection because these changes affect secondary control. With regards to your comment concerning different "regulatory jurisdictions", this issue is outside the scope of the project approved SAR.		
Independent Electricity System Operator	No	We have a difficulty understanding the basis for some of the dates in the implementation plan.Some of the implementation steps (retiring R5 of BAL-003-0) start as early as May 2011. We do not believe that the BAL-003-1 standard will be approved by the industry or the NERC BoT at that time and that does not even take into account regulatory approval (or 12 months after BoT adoption in those jurisdictions where no regulatory approval is required). How can a standard begins to phase out while the successor standard is not anywhere near becoming effective?If the SDT wants to propose a gradual replacement of the current R5, we would suggest that the phase-out steps be tied to the date that the standard becomes effective.
Response: The SDT has added the R5 Requirement back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make		

Organization	Yes or No	Question 7 Comment
necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent.		
Southern Company	Yes	We did not want to vote on Question 7, but clicked 'yes' in error.
Response: The SDT thanks you for your clarifying comment.		
Westar Energy	Yes	Yes, if field testing validates the standard.
Response: The SDT thanks you for your affirmative response and clarifying comment. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent.		
Associated Electric Cooperative, Inc.	Yes	
NorthWestern Energy	Yes	
ENBALA Power Networks	Yes	
SPP Standards Development	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
SERC OC Standards Review Group		The implementation plan has specific dates for reducing the bias settings currently defined in Requirement 5 over several years. Perhaps these dates should not be specific but tied to months following regulatory approval. Attachment A should be modified to match what is in the proposed standard. The values currently shown as percent “of peak/0.1 Hz” should be changed to percent of estimated yearly peak demand per 0.1 Hz change. For BAs that do not serve native load, percent “of upcoming years maximum generation/0.1 Hz should be changed to percent of its estimated maximum generation level in the coming year/0.1 Hz change.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td colspan="3"> Response: The SDT has added the R5 Requirement back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent. Attachment A has been revised for clarity. </td></tr>
<tr><td>Arizona Public Service Company</td><td></td><td> AZPS has a few questions: 1) has frequency performance been affected by the on-going RBC field trial, 2) what steps will be taken to isolate this field trial from the effects of the RBC field trial, 3) will the frequency bias reduction to 0.8% of peak load include a CPS2 grace-period for thos BAs not involved in the RBC field trial? </td></tr>
<tr><td colspan="3"> Response: 1) The Frequency Response SDT cannot respond on RBS field trial matters. 2) This standard is meant to addresses primary control and the settings of the bias which would have an impact on the measures of the RBS field trial. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT believes that it is necessary to observe the affect each decrement to the present standard has during all four seasons to assure reliability is not adversely impacted. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. The SDT believes the revised plan is doable and prudent. 3) The Frequency Response SDT anticipates the RBC field trial will be concluded when this standard takes effect. The SDT is proposing that standards requirements take effect for all entities within a regulatory jurisdiction at the same time. </td></tr>
<tr><td>Northeast Power Coordinating Council</td><td></td><td>Refer to the response to Question 17.</td></tr>
<tr><td colspan="3">Response: Please refer to the SDT response to Question 17.</td></tr>
</table>

8. *This standard proposes to eliminate the 1% minimum Frequency Bias over a period of 4 years as outlined in the Implementation Plan. Do you agree that the elimination of the 1% minimum will bring Frequency Bias closer or equal to natural Frequency Response? If not, please explain in the comment area.*

Summary Consideration: Comments received indicate commenters are divided over whether elimination of the 1% minimum will bring Frequency Bias closer or equal to the natural Frequency Response. Many commenters indicated that the Frequency Bias Setting will never match the Frequency Response and that it is far better for reliability to over bias than under bias. Commenters also expressed concern with how the Frequency Response Obligation (FRO) will be calculated; the rationale for the phase out schedule; and the impact this proposal will have on secondary control.

The FR SDT refined language to indicate it is better to have a somewhat over bias condition, provided additional details on how the FRO is calculated, explained the rationale for the phase out schedule proposed; including developing a reasonable, practical and accurate measurement for natural Frequency Response.

Organization	Yes or No	Question 8 Comment
MRO's NERC Standards Review Subcommittee	No	We do note that the question asks if we disagree with eliminating Frequency Bias over a four year period. The requirement actually applies to Frequency Bias Setting. This is important because there has been confusion in some regulatory filings over the Frequency Response versus Frequency Bias Setting. Our comments below assume that Frequency Bias Setting was intended to be used in the question since it is what is in the BAL-003-0.1b R5. We do not question the plan to change the minimum Frequency Bias Setting over a period of 4 years per se in attempt to optimize AGC response by matching the Frequency Response of the system. However, Frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to overbias that underbias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for Frequency Bias Setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the Frequency Bias Setting to ensure that the bias setting is overbiased.
Response: The SDT agrees with your clarification that the 1% minimum applies to the Frequency Bias Setting. We also agree to evaluate the need to be somewhat (as opposed to extremely) over-biased. For example, if a Balancing Authority's observed Frequency Response was .4% of its annual forecasted peak load then, at a minimum, a value such as .1% would be added to the Frequency Bias setting to make it less likely that the Frequency Response will be counteracted by AGC actions.		
Midwest ISO Standards Collaborators	No	We do note that the question asks if we disagree with eliminating Frequency Bias over a four year period. The requirement actually applies to Frequency Bias Setting. This is important because there has been confusion in some regulatory filings over the Frequency Response versus Frequency Bias Setting. Our

Organization	Yes or No	Question 8 Comment
		comments below assume that Frequency Bias Setting was intended to be used in the question since it is what is in the BAL-003-0.1b R5.We do not question the plan to change the minimum Frequency Bias Setting over a period of 4 years per se in attempt to optimize AGC response by matching the Frequency Response of the system. However, frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to overbias that underbias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for Frequency Bias Setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the Frequency Bias Setting to ensure that the bias setting is overbiased.
Response: The SDT agrees with your clarification that the 1% minimum applies to the Frequency Bias Setting. We also agree to evaluate the need to be somewhat (as opposed to extremely) over-biased. For example, if a Balancing Authority's observed Frequency Response was .4% of its annual forecasted peak load then, at a minimum, a value such as .1% would be added to the Frequency Bias setting to make it less likely that the Frequency Response will be counteracted by AGC actions.		
We Energies	No	We do note that the question asks if we disagree with eliminating Frequency Bias over a four year period. The requirement actually applies to Frequency Bias Setting. This is important because there has been confusion in some regulatory filings over the Frequency Response versus Frequency Bias Setting. Our comments below assume that Frequency Bias Setting was intended to be used in the question since it is what is in the BAL-003-0.1b R5.We do not question the plan to change the minimum Frequency Bias Setting over a period of 4 years per se in an attempt to optimize AGC response by matching the Frequency Response of the system. However, frequency Response of the interconnection is constantly changing. As a result, the Frequency Bias Setting will never match the Frequency Response exactly. It is better to over-bias than under-bias to prevent withdrawal of frequency response by AGC. Historically, the 1% floor for Frequency Bias Setting was chosen to ensure that BAs are always over-biased. The standard needs to allow some margin in the Frequency Bias Setting to ensure that the bias setting is over-biased
Response: The SDT agrees with your clarification that the 1% minimum applies to the Frequency Bias Setting. We also agree to evaluate the need to be somewhat (as opposed to extremely) over-biased. For example, if a Balancing Authority's observed Frequency Response was .4% of its annual forecasted peak load then, at a minimum, a value such as .1% would be added to the Frequency Bias setting to make it less likely that the Frequency Response will be counteracted by AGC actions.		
Bonneville Power Administration	No	Until the calculations used for FRO are spelled out and how natural Frequency Response is to be measured, BPA cannot agree that elimination of the 1% minimum will bring Frequecy Bias closer or equal to natural Frequency Response.
Response: The SDT has provided clarification in Attachment A, Attachment B and the Background Documents.		
IRC Standards Review	No	Please provide the technical basis for the 4-year phase-out schedule.

Organization	Yes or No	Question 8 Comment
Committee		The SRC suggests that incremental changes should be made and evaluated to determine whether they are indeed beneficial before additional changes are made. Until a standard is defined, it is not appropriate to set an implementation date on the transition. Also, please clarify that the process is to gather data, analyze that data to determine what has been the actual frequency response, and then to determine the Frequency Bias Settings to be closer to or equal to the natural frequency response, and is not saying that the next actual frequency response must equal the Frequency Bias Setting that the ERO has assigned. There is a subtle difference here that must be clarified in order to avoid the unintended consequence of "punishing" an entity for not providing a response equal to the Frequency Bias Setting.
Response: The technical basis for the phase out schedule is to allow time to evaluate how each Frequency Bias Setting change impacts both reliability and control criteria CPS1 and CPS2 performance. The intent of the Implementation Plan proposed was to evaluate the effectiveness of each setting change before additional refinement to the Frequency Bias Setting is made and incorporated into the AGC algorithm. This has been removed from the Implementation Plan. The SDT has chosen an alternate method for reducing the minimum Frequency Bias Setting. Standard language is not intended to penalize entities for not providing a response equal to its Frequency Bias Setting. The intent of the standard is to establish a Frequency Response Obligation (FRO) representing the minimum response required for reliable interconnected operations. The Frequency Bias Setting can differ from the determined FRO value as appropriate for reliability for which compliance will only evaluate if the Frequency Bias Setting is refined correctly and implemented in a timely manner.		
ERCOT	No	Please provide the technical basis for the 4-year phase-out schedule. The SRC suggests that incremental changes should be made and evaluated to determine whether they are indeed beneficial before additional changes are made. Until a standard is defined, it is not appropriate to set an implementation date on the transition. Also, please clarify that the process is to gather data, analyze that data to determine what has been the actual frequency response, and then to determine the Frequency Bias Settings to be closer to or equal to the natural frequency response, and is not saying that the next actual frequency response must equal the Frequency Bias Setting that the ERO has assigned. There is a subtle difference here that must be clarified in order to avoid the unintended consequence of "punishing" an entity for not providing a response equal to the Frequency Bias Setting.
Response: The technical basis for the phase out schedule is to allow time to evaluate how each Frequency Bias Setting change impacts both reliability and control criteria CPS1 and CPS2 performance. The intent of the Implementation Plan proposed was to evaluate the effectiveness of each setting change before additional refinement to the Frequency Bias Setting is made and incorporated into the AGC algorithm. This has been removed from the Implementation Plan. The SDT has chosen an alternate method for		

Organization	Yes or No	Question 8 Comment
reducing the minimum Frequency Bias Setting. Standard language is not intended to penalize entities for not providing a response equal to its Frequency Bias Setting. The intent of the standard is to establish a Frequency Response Obligation (FRO) representing the minimum response required for reliable interconnected operations. The Frequency Bias Setting can differ from the determined FRO value as appropriate for reliability for which compliance will only evaluate if the Frequency Bias Setting is refined correctly and implemented in a timely manner.		
Kansas City Power & Light	No	Simply eliminating the minimum frequency response and establishing an FRO obligation for each BA will not result in a knowledge that a BA has moved closer to its natural frequency response. First, there is an underlying assumption that the FRO dictated for the BA will be “matched” by a BA’s resources to achieve a natural response close the FRO and until improved methods of calculating a BA’s actual frequency response are developed, there will be no accurate way of determining if a natural response is close to the FRO obligation.
Response: The intent of the first sentence in the comment above is not clear. There is no underlying assumption that natural response will match the frequency response obligation. However, the compliance process will provide a stimulus to the BA to achieve at least that level of frequency response. The FR SDT is expending considerable effort to develop a reasonably accurate measurement of natural response, and is in the process of choosing among several promising metrics.		
NorthWestern Energy	No	Page 2 implies that there is currently too much frequency response based on the 1% of peak demand method of establishing frequency bias. Even though NWE does not use the 1% method, NWE feels that the 1% minimum has been a tried and true method of providing frequency response in the Western Interconnection. Without the 1% minimum (and BA’s using a natural response less than the 1%), the total interconnection frequency response would decrease according to research. This would lead to decreased interconnection bias, causing other operational issues, such as lower L10 values and possible CPS2 compliance factors.
Response: The opening sentence of this comment appears to be a misstatement. The FR SDT believes a gap exists between the natural Frequency Response and the Frequency Bias Settings calculated based on the 1% of peak demand criteria, resulting in excessive and unnecessary regulation occurring that is related to high frequency conditions following DCS events and other circumstances. The FR SDT agrees that a reduction in the 1% of peak demand criteria for the Frequency Bias Setting can adversely affect the overall Interconnection Frequency Bias Setting, L10 values, and possibly CPS 2 compliance also.		
Westar Energy	No	The 1% requirement should be phased out with the implementation of this standard.
Response: The technical basis for the phase out schedule is to allow time to evaluate how each Frequency Bias Setting change impacts both reliability and control criteria CPS1 and CPS2 performance.		
FMPP	No	There still needs to a floor value; 1% may not be the correct value, but zero is not the correct floor.

Organization	Yes or No	Question 8 Comment
Response: The floor will not be zero. Each Balancing Authority will have a required FRO contribution reflective of the natural Frequency Response in its Frequency Bias Setting.		
American Electric Power	No	Please see response to question 7.
Response: Please see our response to Question 7.		
Duke Energy	No	Duke Energy agrees that a gradual reduction (in magnitude) of the minimum as part of the field test is needed to determine what is the "right" amount of response needed, but the changes cannot be done in a vacuum. Duke Energy continues to be concerned with the impact that the changes to the Frequency Bias Setting ("FBS") will have on the bounds guiding secondary control (CPS1, CPS2 and the draft Balancing Authority ACE Limit or "BAAL" currently under a Field Trial under NERC Project 2010-14). Eastern Interconnection Frequency Response: For those not familiar with the work of the FRRSDT or the NERC Resources Subcommittee around Frequency Response, the estimated response for the Eastern Interconnection on average appears to be less than half of the Interconnection's total FBS in magnitude today. If the decision was made to hold Frequency Response at its current level, this standard could result in the FBS being reduced for many, if not most, Balancing Authorities to about half of what it is today. The FRO allocation would eventually drive what the minimum FBS needs to be, with the FBS needing to be greater than or equal to the FRO, or perhaps FRM, in magnitude at a minimum. Estimating the impact: To look further into the secondary control performance implications of BAs using a reduced FBS, Duke Energy took four sample months of clock-minute data for twelve BAs, cut the Interconnection total and each BA's FBS in half, recalculated each BA's clock-minute ACE taking out half of the bias component, and then calculated CPS1, CPS2 and BAAL estimated performance based upon those changes. Recognizing that the secondary control and resulting ACE of the BAs would be different and dependent upon the standards to be met, the results were not intended to estimate what the performance of the BAs would be, but were intended to help indicate where the problem areas existed based upon today's operation measured to a tighter control criteria. Impact on CPS1 and BAAL: The two bounds that are frequency-dependent, CPS1 and the draft BAAL, are cut in half for any given frequency by cutting the FBS in half. For CPS1 the impact of reducing the FBS looked reasonable with the results leaning toward overall improvement in CPS1 for almost half or better of the BAs (5 of 12, 8 of 12, 6 of 12, and 12 of 12) for the given months even with the tighter bounds, but more analysis may be needed. Though CPS1 looks manageable, the sample set did not include small BAs, and some BAs already in the 100-120% range appeared more at risk. For BAAL the longest duration of ACE exceeding the low or high BAAL stayed the same or got worse in all cases. As with today where the BAAL bounds get wider as frequency gets closer to 60 Hz where the majority of operation occurs, the additional flexibility of operation is offset by the BAAL bounds getting tighter than the CPS2 limits as frequency deviates farther from 60 Hz. With BAAL cut in half for this scenario, compliance will be more challenging and costly to manage to not exceed 30 minutes for any event. One of the

Organization	Yes or No	Question 8 Comment
		unknowns is whether the Frequency Trigger Limit for the BAAL calculation will stay where it's at or be lowered, as the current value was based upon UFLS at 59.82 Hz, rather than today's UFLS of 59.7 Hz. The BARCSDT under NERC Project 2010-14 has more work ahead before any changes can be proposed.Impact on CPS2: Though the industry is not seeing a reliability need to tighten secondary control in normal operation, the industry can't avoid such "tightening" with CPS2 limits directly dependent upon the FBS of the Balancing Authority and total FBS of the Interconnection. For the four months reviewed where CPS2 limits were cut in half, if one looked at the results individually the drop in CPS2 performance across the twelve BAs ranged from 2.6% to 33.8%, 4% to 33.5%, 3.8% to 37.8%, and 3.1% to 35.1%, with a median of 19.4%, 18.4%, 20.3% and 18.9% for the four months. Noting that CPS2 performance must be 90% or greater on a monthly basis, improving CPS2 performance by even 10% translates to over 70 hours of operation in a month where additional secondary generation control and other actions may be required. Duke Energy notes also that with less error in the ACE, the results indicate that the distribution of ten-minute events exceeding L10 would move closer toward the 50-50 chance that CPS2 will be forcing control action even though the ACE is in support of the Interconnection frequency (results showing the average moving from 27-34% to 39-43% of the ten-minute periods exceeded when in support of Interconnection frequency).Conclusion: Duke Energy does not believe there is a reliability need pushing the industry to tighten secondary control to the degree discussed above simply as a result of reducing the Frequency Bias Setting. If the calculated Frequency Response of the Interconnection stayed at its current level, what would be the justification for tightening the secondary control requirements of CPS1, CPS2 and the proposed BAAL? Duke Energy supports taking more of the error out of the ACE equation by having the FBS closer to the estimated Frequency Response of the Balancing Authority, however, Duke Energy does not believe the result should be a significant increase in secondary control costs to meet the CPS1, CPS2, or draft BAAL requirements.
Response: The SDT appreciates receiving this analysis of the impact Frequency Bias setting can have on secondary control. Please continue to analyze and share this technical data to the extent possible with the SDT. The SDT will perform comparable analyses during the field trial for determining the proper balance between having less "over control" than is perceived with respect to possibly increasing the secondary control cost incurred by individual Balancing Authorities because a smaller Frequency Bias Setting is utilized.		
Alberta Electric System Operator	No	The standard seems to propose to replace the 1% minimum frequency bias with the new proposed FRO. The AESO finds it difficult to comment on if it is not clear on how the FRO is determined.
Response: The Frequency Response Obligation is used for determining if there is sufficient primary Frequency Response for reliability. The minimum Frequency Bias Setting to be used in AGC will have a floor value needed to assure reliable control, and can be different than the Frequency Response Obligation. The SDT has modified Attachment A to provide additional clarity regarding the calculation methodologies.		
Independent Electricity System Operator	Yes	We do not have an opinion on the proposed elimination but do have a difficulty understanding the phase-out plan. Please see our comments under Q7, above.

Organization	Yes or No	Question 8 Comment
Response: The FR SDT has created Attachment B to provide clarifying language for the phase-out plan. Please refer to the SDT response to question #7.		
SPP Standards Development	Yes	While we agree that we think such a change will move the industry in the right direction, we have nothing upon which to base that opinion. On the other hand, the 1% minimum does provide a safety net for the interconnection. Moving away from the minimum requirement over a 4-year period should give us the necessary operating experience to become more confident in our numbers.
Response: The goal of the phase-out plan is to determine the best Frequency Bias Setting floor value to use for reliability that is based on a measured and cautionary approach.		
Southern Company	Yes	Comments: Agree only to the extent that the natural Frequency response can be accurately determined.
Response: The FR SDT is investing considerable effort on behalf of industry to develop a reasonable, practical and accurate measurement of natural frequency response and also a process for choosing the best of several promising metrics.		
Progress Energy	Yes	We have seen actual system operations harmed by the current, excessive biasing requirement on several occasions.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
NIPSCO	Yes	Obviously it will bring it closer. The 4 year phase-in is a great idea.
Response: The SDT thanks you for your affirmative response and clarifying comment..		
Manitoba Hydro	Yes	Yes, the removal of the 1% of projected peak load which has a large window of probability for error should improve BIAS calculations.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Patterson Consulting, Inc.	Yes	Moving Frequency Bias Settings closer to natural Frequency Response is critical to improving observation, reporting, and control.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 8 Comment
EKPC	Yes	
Energy Mark, Inc.	Yes	
Beacon Power Corporation	Yes	
ENBALA Power Networks	Yes	
SERC OC Standards Review Group	Yes	
FirstEnergy	Yes	
Santee Cooper	Yes	
LG&E and KU Energy	Yes	
Arizona Public Service Company	Yes	
Seattle City Light	Yes	
ISO New Engand Inc.		With .4% peak load being a typical actual frequency response lately for Balancing Authorities, the 1% of peak load to .8% of peak load transition seems prudent. Perhaps a further reduction to .6% may be useful as well, but lesser floors may in effect result in AGC too often canceling out the primary frequency response being provided.
Response: The SDT thanks you for your clarifying comment.		
Associated Electric Cooperative, Inc.		I agree with this emerging standard's recognizing that the arbitrary 1% of peak-load should be refined by being lowered to better reflect each BA's expected frequency response.
Response: The SDT thanks you for your clarifying comment.		
Northeast Power Coordinating Council		Refer to the response to Question 17.

Organization	Yes or No	Question 8 Comment
Response: Please refer to the SDT response to Question 17.		

9. *Do you agree with the drafting team that this standard should be field tested? If not, please explain in the comment area.*

Summary Consideration: The majority of the commenters agreed that this standard should be field tested. Most commenters indicated that the implementation plan should include information regarding the field trial and also be coordinated with the field trial schedule. Individual commenters suggested that the field trial is not required if detailed calculations and definitions were provided to entities for implementations and the field trial should not serve as a pre-established standard.

In response to industry feedback received, the SDT is presently field testing the methodologies for calculating FRM and FRO. The reduction of the Frequency Bias Setting is no longer part of the field trial. The SDT has defined a process for the ERO to follow to reduce the minimum Frequency Bias Setting once this proposed standard has been approved..

Organization	Yes or No	Question 9 Comment
FirstEnergy	No	We believe that the implementation plan should include information regarding the field trial and how it fits in with the phase-in implementation. It appears as though the field trial is being conducted based on 2010 data and will be concluded upon completion of the development of the standard but we think this could be clarified. Furthermore, as stated in the process manual, a field test "should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results." The field test information posted is not clear on the implementation schedule of the field test as well as when and how periodic updates will be available.
Response: Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Bonneville Power Administration	No	BPA believes that this standard as written should not be field tested. The calculations to be used to set frequency bias must be spelled out in detail and the definition of natural Frequency Response under multiple loading conditions must also be detailed. Once these conditions have been adequately met, there will not be a need for a field trial.
Response: Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections.		

Organization	Yes or No	Question 9 Comment
Please refer to Attachment B for reduction plan details.		
MRO's NERC Standards Review Subcommittee	Yes	The field test is not identified in the implementation plan. It should be.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary correction. Please refer to Attachment B for reduction plan details.		
Midwest ISO Standards Collaborators	Yes	The field test is not identified in the implementation plan. It should be.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
SPP Standards Development	Yes	Field testing will provide an opportunity to learn as we move forward with the standard. Modifications can be made as experience is gained and knowledge is acquired.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary correction. Please refer to Attachment B for reduction plan details.		
IRC Standards Review Committee	Yes	A Field Test, sometimes called a Field Trial, is appropriate to identify and establish methods, but it should be a Field Trial, not a pre-established standard. The standard should be put into place later after the technical determinations have been accomplished. The time required for the field test should be taken into account when developing the implementation plan, especially the phase-out plan for R5.

Organization	Yes or No	Question 9 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
ERCOT	Yes	A Field Test, sometimes called a Field Trial, is appropriate to identify and establish methods, but it should be a Field Trial, not a pre-established standard. The standard should be put into place later after the technical determinations have been accomplished. The time required for the field test should be taken into account when developing the implementation plan, especially the phase-out plan for R5.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
ISO New Engand Inc.	Yes	A Field Test, sometimes called a Field Trial, is appropriate to identify and establish methods, but it should be a Field Trial, not a pre-established standard. The standard should be put into place later after the technical determinations have been accomplished.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Arizona Public Service Company	Yes	What criteria will be used to evaluate the field trial? What constitutes acceptable/non-acceptable results? [see also, comments to question 7]
Response: Please refer to our comments for Question 7.		
Progress Energy	Yes	This plan should be field tested, although it feels as though this is less of a "field test" based on engineering judgement and more of trial and error testing. This problem should be studied to determine what is necessary

Organization	Yes or No	Question 9 Comment
		to manage system frequency within desired limits for the worst single contingency during the period of time the system is most vulnerable (minimum load). The result should be spread proportionally to all BAs in the interconnection, and those BAs should respond to and bias their ACE equation by the required value.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details. Attachment A has been revised to clarify the calculation methodology.		
NIPSCO	Yes	Great idea
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Westar Energy	Yes	This is a major change and field testing is required to valid the standard and allow for revisions based on testing results
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Manitoba Hydro	Yes	Yes, to ensure the eastern interconnection frequency health does improve with these new methods and if it does each BA will have a more accurate and fair BIAS setting.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
American Electric Power	Yes	The changes proposed should be thoroughly tested before any implementation.

Organization	Yes or No	Question 9 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Patterson Consulting, Inc.	Yes	A field test will provide valuable refinment and verification of parameters, and should identify unexpected ramifications.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
South Carolina Electric and Gas	Yes	We do agree that a field test should take place but more details on the field test would be helpful.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Independent Electricity System Operator	Yes	The time required for the field test should be taken into account when developing the implementation plan, especially the phase-out plan for R5.
Response: The SDT thanks you for your affirmative response and clarifying comment. Requirement R5 has been inserted back into the proposed standard. SDT has revised the plan for reducing the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table showing the reduction schedule for the minimum bias setting. The SDT is proposing another method for reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reduction and make necessary corrections. Please refer to Attachment B for reduction plan details.		
Santee Cooper	Yes	

Organization	Yes or No	Question 9 Comment
LG&E and KU Energy	Yes	
SERC OC Standards Review Group	Yes	
Kansas City Power & Light	Yes	
Southern Company	Yes	
ENBALA Power Networks	Yes	
NorthWestern Energy	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	
EKPC	Yes	
We Energies	Yes	
Alberta Electric System Operator	Yes	
Duke Energy	Yes	
Seattle City Light	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		

10. *Attachment A of the proposed standard describes the criteria for selecting events to be analyzed. Do you agree with the criteria as described in Attached A? If not, please explain in the comment area.*

Summary Consideration: Comments received indicate the majority of commenters agree with having criteria for selecting events to be analyzed and requested clarification on the rationale for the criteria proposed. Research performed by the FRR SDT indicates analysis using 25 events and mean frequency data values will result in stable, consistent results.

Many commenters also expressed concern that the selection criteria was too stringent; that criteria language would omit selection of events worth reviewing; that Balancing Authorities should have flexibility in choosing which event data is selected and also have ability to modify submitted data for ensuring accuracy; and that using event data from the prior year could create double jeopardy. The intent for frequency values selected is to ensure most generators responsive to the interconnection will experience a governor response. The FRR SDT also agrees that interconnection subject matter experts and Balancing Authorities require the flexibility to select noteworthy events of interest, flexibility to identify which events to include or exclude for analysis, and allowance for modifying data for quality and other relevant concerns. The FRR SDT also believes that in those years where 25 acceptable events do not exist, stability and consistency concerns outweigh any adverse impacts from utilizing a few events from the previous year for analysis and that actual impact on current year results will be negligible.

After reviewing comments, the FRR SDT has revised Attachment A language for clarity. The team separated the rationale into a separate document and also revised Form-1.

Organization	Yes or No	Question 10 Comment
Santee Cooper	No	In Attachment A, item 2.b. states that “The time from the start of the rapid change in frequency until the point at which Frequency has largely stabilized should be less than 18 seconds.” It appears that this statement was to ensure that frequency is rapidly decaying; however, frequency could continue to decay beyond 18 seconds and should still be considered an event. Item 3 states that point A is calculated as “an average” is this considered to be an average of all samples or selected samples. Also, we would like to know how the different thresholds for the interconnections were determined. We are also concerned with how the threshold would affect compliance to the standard if it was ever required to be measured on an event basis, particularly those events close to the threshold dead-band settings. Words such as “assumed” should be avoided. Please explain how the number of 25 events was determined for the list of frequency events and explain how those events will be distributed throughout the year (i.e., on and off-peak, and seasonal).

Organization	Yes or No	Question 10 Comment
		Events that meet the selection criteria should be posted by the ERO on a monthly basis. This will allow BAs to evaluate their performance throughout the year.
Response: The intent for using the words "largely stabilized" in the sentence provides desired flexibility for selecting events for analysis. For example, if frequency drops from 60 Hz to 59.94 Hz in 6 seconds and then continues to decay to 59.935 Hz over the next 20 seconds; then this event would be selected for analysis. With respect to point A, all available samples for the time window specified are averaged. The number of samples obtained for averaging will be determined by the Balancing Authority's EMS scan rate. Each Interconnection threshold will be determined by subject matter experts who have knowledge of the historical events being analyzed, CERTS research and field trial results. It is not the intent of this standard to seek compliance on a per event basis especially since data quality issues make this type of analysis difficult to validate. Analysis of metrics being considered by the SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. The SDT expects the sample set to include seasonal, on-peak, and off-peak events that satisfy the selection criteria specified. The SDT proposes posting event data on a quarterly basis so Balancing Authorities can periodically analyze data during the year. Attachment A has been divided into two separate documents; a revised Attachment A containing the calculation methodology and a Background Document explaining the development rationale for the standard's requirements and measures.		
Bonneville Power Administration	No	BPA does not agree with the criteria described in the attachment. 36 mHz is not a large enough deviation to adequately measure frequency response. There is no need to go to that small of a deviation in order to insure that 25 events are found over the course of a year.
Response: The FR SDT will consult with WECC subject matter experts to refine the frequency deviation selection criteria for the western interconnection. Keep in mind the selection threshold will be adjusted over time, as supported by evidence, to ensure reasonable selection criteria is utilized.		
SPP Standards Development	No	While Criteria 5 allows for the ERO to exclude 'non-conforming' SEFRD points there isn't a mechanism provided that instructs us on how to exclude those points in FRS Form 1. Would we be required to reach out for an additional point to get us back to 25 if a point is excluded? Who excludes the point in question? Is it the BA or is it the ERO? Will the ERO have sufficient knowledge to exclude the point in question? In Critieria 2.a. the first sentence should read "The frequency deviation (Point A minus Point C) must exceed...". Also, 36 MHz should be 36 mHz.
Response: The SDT has developed a new version of FRS Form 1, and it clarifies the process of how a Balancing Authority excludes an event. The ERO will not		

Organization	Yes or No	Question 10 Comment
exclude events. The Balancing Authority would not be required to replace an excluded event with another event since analysis of metrics being considered by the SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. Analysis also shows that the median value is more consistent than the mean value when the sample set includes data for an event that otherwise should have been excluded from the analysis. The SDT thanks you for catching the typographical error referencing 36 mHz. The SDT has revised Attachment A and this value is no longer referenced..		
IRC Standards Review Committee	No	The criteria for events selection are acceptable, but the criteria stated in Attachment A for performance required by the FRO is too stringent. Criteria requiring avoidance of Point C encroachment on step 1 of the UFLS program is more stringent than proven performance that now exists. To make this change will be very costly and will not provide for a commensurate increase in reliability.
Response: FRO values have not yet been selected. The intent is to choose FRO values that are necessary for the reliability of each interconnection.		
ERCOT	No	The criteria for events selection are acceptable, but the criteria stated in Attachment A for performance required by the FRO is too stringent. Criteria requiring avoidance of Point C encroachment on step 1 of the UFLS program is more stringent than proven performance that now exists. To make this change will be very costly and will not provide for a commensurate increase in reliability.
Response: FRO values have not yet been selected. The intent is to choose FRO values that are necessary for the reliability of each interconnection.		
Southern Company	No	Comments: Selecting events just outside the governor deadband (e.g. 36 mHz in the EI) is not a good idea in that it assumes too much precision in the response by governors at the deadband boundary. This will result in a less accurate natural Frequency Response calculation for those large events where knowing an accurate Frequency Response value is most critical. In other words the event selection “deadband” should be somewhat larger than the Governor deadband even those this will result in somewhat fewer events in the final set.
Response: The intent is to choose among the largest frequency deviation events to obtain a meaningful sample set for analysis accuracy. The FR SDT is open to suggestions to refine the selection criteria for each interconnection. A balance needs to be established between having an inadequate sample resulting in less computational accuracy versus having a sample that is not representative of actual response occurring for the larger frequency deviation events of concern.		
Progress Energy	No	It should be explicitly stated that point C must be outside the standard frequency deviation deadband referenced from 60.0 Hz, not a deviation of more than the frequency deviation deadband from the pre-disturbance frequency. Most of the new electronic govenors operate with a 60 Hz center instead of changes in frequency relative to the current value.

Organization	Yes or No	Question 10 Comment
		Additionally, the first limit under number 2 should be 36 mHz, not 36 MHz as they are a factor of 10^9 different. Lastly, the event selection criteria listed in Attachment A uses the frequency as measured at Point C to qualify an event, in an effort to ensure that the deviation exceeds the governor deadband. However, Point C is an instantaneous point which will differ in value within the interconnect based on how close the loss of generation is to the measuring point due to the elasticity of frequency across the interconnect during the inertial response. Therefore, local readings by the BA should be allowed to exempt a specific event if the local frequency did not exceed 36 mHz.
Response: It is expected that the selection criteria will yield events with Point C that clearly exceed the generator governor deadband and result in a response action. While the distance between the measuring point and the loss of generation location will cause different Point C (and other) frequency values being measured at different system locations, the variation in Point C frequency values among the different locations will not be significant for most events or most Balancing Authorities. Keep in mind each Balancing Authority will use its EMS local frequency data for determining sample points A and B. The FR SDT anticipates selecting events that will not require the Balancing Authority to exclude events because of local frequency values measured. The FR SDT will consider high local frequency as a possible selection criteria exclusion factor in the next revision of Form 1.		
NorthWestern Energy	No	Should state " The Point C value is the minimum of frequency samples and should be within 8 seconds after the start of the rapid change". NWE feels some instances could be more than 8 seconds and "should" would allow for this if it occurred.
Response: The original intent was to exclude such events however the SDT understands some of these events may provide interesting and valuable information. Language proposed would give subject matter experts selecting the events necessary leeway to include such events. The SDT will consider changing "shall" language to give subject matter experts more flexibility with selecting events.		
Hydro-Quebec TransEnergie	No	The criteria to determine what should be considered as a frequency event should be defined by Interconnection. For example, HQT has no dead band on governors; therefore the 36 mHz is not applicable. If more than 25 events occurred within a year, will they all be selected or only a set of 25 will be? Who will perform this selection and base on what criteria.
Response: Event selection criteria will be specified on an interconnection basis after consulting with subject matter experts for that interconnection. Selected events will be chosen by subject matter experts for that interconnection.		
Westar Energy	No	The lagging measure is a concern. The ERO should be required to provide an updated proposed/possible list of frequency events monthly so BA's can determine their FRM through out the year so corrective action can be taken if needed. Prior year events should be excluded (just to get to 25 events). This could result in begin non-compliant twice for the same events. If a BA is over performing in the first of the year and adjusts in the second half of the

Organization	Yes or No	Question 10 Comment
		year then those second half of the year events are used in the next year, it could cause an inappropriate violation. BA's need the ability to exclude some events based on measure issues with specific events including scan rates, unusual intermittent resource changes, non-conforming load, unusual ramping of load or interchange during the event.
Response: Based on comments received from industry, the SDT proposes posting event data on a quarterly basis so Balancing Authorities can periodically analyze data during the year. Generally, each Balancing Authority will have 25 acceptable events occur each calendar year. Using a few events from the preceding year is not expected to adversely affect accuracy of analysis results. The SDT is re-evaluating exclusionary criteria and is also developing a process to permit reasonable adjustments to an event for atypical circumstances.		
FMPP	No	Attachment A states that if a year occurs in which there are not 25 events that meet the remaining criteria below, then the most recent 25 events (as defined below) will be used for determination of an entity's compliance with the FRM requirement and storage of SEFRD. Problem - by using events from last year to determine an entity's compliance with a Requirement for this year puts the entity in double jeopardy for last year's events, which were already used for compliance for last year. Attachment A states that events occurring during periods in which either significant interchange schedule ramping or load ramping is likely, should be excluded if other events are available for measurement purposes. Questions - What is significant?How can the ERO determine significant interchange schedule ramping is likely?Likely for how many BAs?It would be better to define significant and let the BA exclude any events that meet this definition, since each BA will be ramping differently. Since SEFRD is defined as the individual sample of event data from a Balancing Authority which represents the change in Net Actual Interchange (NIA), divided by the change in frequency, expressed in MW/0.1Hz, whenever a BA includes an event with a "significant" change in NIA due to a large interchange schedule ramp, the FRM is totally skewed, and should not be included. If other events are available means that if other events are not available then an entity's compliance is going to be based on an event or events that has been skewed for the BA by significant interchange schedule ramp.
Response: Generally, each Balancing Authority will have 25 acceptable events occur each calendar year. Using a few events from the preceding year is not expected to adversely affect accuracy of analysis results. The SDT is re-evaluating exclusionary criteria and is also developing a process to permit reasonable adjustments to an event for atypical circumstances. The SDT does not expect subject matter experts will select events with rapid load change or large schedule change activity. Large schedule changes typically occur between 7 AM and 8 AM, and 10 PM and 11 PM, with 10 minute ramps across the top of the hour. Having Balancing Authorities exclude these kinds of events could be problematic because balancing areas are different in size from one Balancing Authority to the next. The SDT has developed a manual correction capability for the sampling process which, when used in conjunction with median value rationale, should minimize the impact data skewing tendencies may have on analysis results.		

Organization	Yes or No	Question 10 Comment
American Electric Power	No	Attachment A only appears to be attempting to address the frequency bias setting for AGC portion of overall frequency response without addressing the governor response portion issue. Attachment A still tries to address the issue solely at the Balancing Authority level without addressing criteria at the Generator & Generator Operator levels. WECC has stated through previously submitted comments from its three extensive validation result tests on frequency response with respect to 5% droop for a 0.1 Hz frequency deviation that actual response would be 2.5 times greater if the proper governor response actually occurred. The studies also showed only 40% of the governors effectively responded. Extensive test result studies such as WECC's should not be ignored. Attachment A criteria does not address the lack of frequency response from contributing factors associated with actual governor response, impact of droop setting, amount of BA generation actually on-line at time of event, maximum loading of generation and amount of BA imported interchange to meet load.
Response: The need for an accompanying generation SAR has been discussed and is outside of the current FR SDT scope. Verification of generator governor response is important. The FR SDT encourages entities to continue studying generator governor response and related contributing factors cited.		
Patterson Consulting, Inc.	No	I agree that criteria for event selection are needed, although these criteria appear to be unnecessarily subjective. Items 1 and 2 are appropriate. However, item 3 seems to eliminate many events that should be reviewed. For example, item 3 would eliminate any event with an initial frequency that is not 60 Hz, depending on the subjective determination of "near" and "relatively steady." Similarly, items 5 and 6 add more subjectivity to the selection of events, but may be necessary. It is not clear that criteria listed in Attachment A are required to be used since much other content appears to be explanatory, contextual, and instructional. These explanatory, contextual, and instructional aspects are important, but should not be requirements. Attachment A should be limited to event selection and calculations necessary to support the stated requirements. Instructional, etc. information should be moved to another document. If other "requirements" are included in Attachment A, they should be moved to the standard. FRS Form 1 should be an attachment as this form contains and performs the required calculations. The remaining information in Attachment A should become either a standalone (technical) document, or be combined with information such as "FRS Form 1 Background and Instructions" and renamed. As further clarification regarding the ambiguity identified in the previous paragraphs, Attachment A could be interpreted as additional requirements on the Balancing Authority, ERO, or both. The language and scope are not sufficiently clear to identify whether statements are informative or requirements. This lack of clarity makes it impossible for entities to identify requirements, acquire appropriate tools and resources related to requirements, and to provide suitable performance to meet requirements. For example, the statement "A final listing of official events to be used in the calculation will be available from NERC by December 10 each year." may be intended as a requirement rather than a statement suggesting a typical schedule. Further, if the

Organization	Yes or No	Question 10 Comment
		previous statement is a typical schedule, then the statement "The ERO will use the following criteria for the selection of events to be analyzed." could be interpreted as merely the typical process to be used, but not a binding one. In short, the purpose and intention of Attachment A is not communicated unambiguously.
Response: Item 3 was intended as guidance to give subject matter experts flexibility in choosing the best possible events for analysis. The SDT recognizes that in some years valid but less than ideal events from a selection criteria perspective may be chosen for analysis. The SDT will improve document clarity and also consider if it is prudent to make selection criteria hard or soft requirements. Attachment A has been divided into two separate documents; a revised Attachment A containing calculation methodology and a Background document explaining the development rationale for the standard requirements and measures.		
Xcel Energy	No	1) Using 25 events is likely excessive in the Western Interconnection. Several of the past few years have had less than 10 events. Given the extent to which generation is built and resource profiles change, projecting 25 events will include events in the bias calculation that are less reflective of the current generation profile and skew our bias results. 2) Calculating point A as "...an average over the period from -16 second to 0 seconds" for any event that meets the criteria set in Attachment A means that Point A will likely be within 1-2 mHz of 60 Hz, regardless of starting system conditions. This can cause data to be skewed, as the response will appear to be less if the frequency immediately before the event is further from 60 Hz than the average. Further, it requires additional data. If there is some corrupted data in the 16 seconds prior to the event, it may be required to throw out event data. The 16 seconds prior to the event is not useful data. 3) Point 5 addresses excluding events "...in which significant interchange schedule ramping or load ramping is likely..." Not only are the FRO and FRM definitions too vague, they require analysis of real time generation and load ramping that may not be realistic. Attachment A should likely include specific criteria for removing events, including lack of reasonable data and, as described here, significant schedule or load ramping, where "significant" is defined.
Response: The SDT has reviewed your concern and determined that the WECC would have sufficient event data to analyze. Keep in mind an ERO specified event can be excluded if data quality issues associated with FRS Form 1 exist. Also, manual adjustment to the actual net interchange value for schedule ramping can be performed for completing FRS Form 1. Event selection criteria will allow sufficient flexibility for subject matter experts to avoid periods of rapid load change (e.g., morning pickup and declining late evening load) and ten minute ramps across the top of the hour to the extent possible. The intention is to guide the subject matter experts in choosing the best data set available so that relatively few adjustments, if any, will be needed.		
LG&E and KU Energy	Yes	While we agree with the basic process, we would like to know how the different thresholds for the interconnections were determined. The review team is also concerned with how the threshold would affect compliance to the standard if it was ever required to be measured on an event basis, particularly those events close to the threshold dead-band settings. Words such as "assumed" should be avoided. Please explain how the number of 25 events was determined for the list of frequency events and explain how those events will be

Organization	Yes or No	Question 10 Comment
		distributed throughout the year (i.e., on and off-peak, and seasonal).The criteria in Attachment A should include how and where the arresting frequency is measured
Response: The SDT thanks you for your affirmative response and clarifying comments. The magnitude of the frequency change and the initial frequency values identified were selected to ensure that most generators responsive to the interconnection will exceed the governor frequency dead band limits. It is not the intent of this standard to seek compliance on a per event basis especially since data quality issues make this type of analysis difficult to validate. Analysis of metrics being considered by the SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. The SDT expects the sample set to include seasonal, on-peak, and off-peak events that satisfy the selection criteria specified. Generally, subject matter experts will use high speed frequency recorder data to select events for analysis. Technology is now available that allows cross-checking data at multiple locations for the same event.		
SERC OC Standards Review Group	Yes	While we agree with the basic process, we would like to know how the different thresholds for the interconnections were determined. The review team is also concerned with how the threshold would affect compliance to the standard if it was ever required to be measured on an event basis, particularly those events close to the threshold dead-band settings. Words such as “assumed” should be avoided. Please explain how the number of 25 events was determined for the list of frequency events and explain how those events will be distributed throughout the year (i.e., on and off-peak, and seasonal).
Response: The SDT thanks you for your affirmative response and clarifying comment. The magnitude of the frequency change and the initial frequency values identified were selected to ensure that most generators responsive to the interconnection will exceed the governor frequency dead band limits. It is not the intent of this standard to seek compliance on a per event basis especially since data quality issues make this type of analysis difficult to validate. Analysis of metrics being considered by the FR SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. The FR SDT expects the sample set to include seasonal, on-peak, and off-peak events that satisfy the selection criteria specified.		
South Carolina Electric and Gas	Yes	While we agree with the basic process, we would like to know how the different thresholds for the interconnections were determined. The review team is also concerned with how the threshold would affect compliance to the standard if it was ever required to be measured on an event basis, particularly those events close to the threshold dead-band settings. Words such as “assumed” should be avoided. Please explain how the number of 25 events was determined for the list of frequency events and explain how those events will be distributed throughout the year (i.e., on and off-peak, and seasonal).

Organization	Yes or No	Question 10 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. The magnitude of the frequency change and the initial frequency values identified were selected to ensure that most generators responsive to the interconnection will exceed the governor frequency dead band limits. It is not the intent of this standard to seek compliance on a per event basis especially since data quality issues make this type of analysis difficult to validate. Analysis of metrics being considered by the FR SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. The FR SDT expects the sample set to include seasonal, on-peak, and off-peak events that satisfy the selection criteria specified.		
Arizona Public Service Company	Yes	AZPS would recommend using a lesser number of events and more severe events in the calculation.
Response: The SDT thanks you for your affirmative response and clarifying comment. A balance needs to be established between having an inadequate sample resulting in less computational accuracy versus having a sample that is not representative of actual response occurring for the larger frequency deviation events of concern.		
NIPSCO	Yes	Pretty good
Response: The SDT thanks you for your affirmative response and clarifying comment.		
EKPC	Yes	Please provide detailed information on the 25 events that will be chosen for the event.
Response: The SDT thanks you for your affirmative response and clarifying comment. Attachment A has been revised to include an improved detailed description of the criteria selection process. The magnitude of the frequency change and the initial frequency values identified were selected to ensure that most generators responsive to the interconnection will exceed the governor frequency dead band limits. It is not the intent of this standard to seek compliance on a per event basis especially since data quality issues make this type of analysis difficult to validate. Analysis of metrics being considered by the FR SDT shows the median or mean frequency data analyzed will converge to a stable state using only 20 event samples obtained for the year being reviewed. The FR SDT expects the sample set to include seasonal, on-peak, and off-peak events that satisfy the selection criteria specified.		
Manitoba Hydro	Yes	Yes, 25 events should be sufficient to determine the FRM, while not overburdening the resources performing the analysis.

Organization	Yes or No	Question 10 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Duke Energy	Yes	
Seattle City Light	Yes	
We Energies	Yes	
Energy Mark, Inc.	Yes	
ENBALA Power Networks	Yes	
Kansas City Power & Light	Yes	
Midwest ISO Standards Collaborators	Yes	
FirstEnergy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Alberta Electric System Operator		AESO suggests that the criteria should also consider including some frequency events where the BA has controlled separation from a region. In the case of Alberta, the frequency deviation is larger than most regional frequency deviations and provides a better measure on Frequency Response. Would the proposed standard permit for BA's to choose these events for inclusion in the determination of the frequency response?
Response: This is not a common occurrence. Very few Balancing Authorities operate in this manner. The expectation is events will be selected by the Balancing Authorities. The Balancing Authority may exclude events from consideration for specific conditions such as data quality issues.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		

11. ***The proposed standard has a document attached to it that describes the SDT's reasoning for the Requirements (Attachment A - Frequency Response Background Document). Do you agree with the SDT that this document is useful and provides a clear understanding of the Requirements? If not, please explain in the comment area.***

Summary Consideration: Several of the commenters did not agree that the Attachment A – Frequency Response Background document in its current form was useful and provided a clear understanding of the Requirements. In general most commenters indicated that Attachment A required correction, greater clarity and did not adequately explain the calculation methodology. The SDT has split Attachment A into two separate documents, revised Attachment A to better explain the calculation methodology, and improved the document's clarity. The SDT also revised FRS Form 1 and the background document for clarity. Several commenters stated Requirement R2 needed additional explanation so the SDT revised Requirement R2. Several commenters also expressed concern the standard was not well defined as drafted so Requirement R5 was inserted back into the draft standard to resolve this concern. Another concern identified that language appeared to give the ERO a blank check to make changes to the standard without an industry vote. Other commenters requested a better explanation for how FRO is determined and why the median value is considered a reliable statistical measure for calculating FRM.

R2. Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control.

R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following:

- The maximum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B.
- The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority per 0.1 Hz change as specified by the ERO in accordance with Attachment B.

Organization	Yes or No	Question 11 Comment
MRO's NERC Standards Review Subcommittee	No	Overall, we agree that the document is helpful. However, we do believe additional explanation is necessary for Requirement 2. It appears that the responsibility for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias

Organization	Yes or No	Question 11 Comment
		Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting. On page 3 in the last paragraph of the Frequency Response Obligation and Allocation section, we suggest expanding the explanation of why Frequency Response Obligation is based on (peak generation + peak load)/2. This will result in less responsibility of Frequency Response today for a generator only control area than there currently is. Since load does respond to frequency, we are not suggesting this is wrong. We think it simply needs to be expanded upon in the explanation. Does load contribute the same amount as generation? If not, perhaps the ratio of gen and load response to total response should be reflected in the calculation.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to provide further clarity as to the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT believes that there is presently no obligation on the generator only BA and that the proposed FRO will place an obligation on the generator only BA. The SDT has modified Attachment A to provide additional clarity concerning the calculation methodology. The SDT believes that this is a methodology that is technologically neutral and provides an FRO allocation across all geographic areas.		
Midwest ISO Standards Collaborators	No	Overall, we agree that the document is helpful. However, we do believe additional explanation is necessary for Requirement 2. It appears that the responsibility for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting.On page 3 in the last paragraph of the Frequency Response Obligation and Allocation section, we suggest expanding the explanation of why Frequency Response Obligation is based on (peak generation + peak load)/2. This will result in less responsibility of Frequency Response today for a generator only control area than there currently is. Since load does respond to frequency, we are not suggesting this is wrong. We think it simply needs to be expanded upon in the explanation. Does load contribute the same amount as generation? If not, perhaps the ratio of gen and load response to total response should be reflected in the calculation.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to provide further clarity as to the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control." The SDT believes that there is presently no obligation on the generator only BA and that the proposed FRO will place an obligation on the generator only BA. The		

Organization	Yes or No	Question 11 Comment
SDT has modified Attachment A to provide additional clarity concerning the calculation methodology. The SDT believes that this is a methodology that is technologically neutral and provides an FRO allocation across all geographic areas.		
We Energies	No	Overall, we agree that the document is helpful. However, we do believe additional explanation is necessary for Requirement 2. It appears that the responsibility for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Thus, we are left wondering who has the responsibility for determining the Frequency Bias Setting.
Response: The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to provide further clarity as to the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
FirstEnergy	No	We believe that more work is needed on this document and the requirements to provide for more clarity.
Response: The SDT has modified the Background Document to provide additional clarity concerning the reasoning behind the proposed requirements.		
Bonneville Power Administration	No	Overall comment: Attachment A does not adequately spell out the methodology that is to be used to determine the correct frequency bias for a Balancing Authority. In order for this standard to go forward, the methodology must be explicitly spelled out and moved into the standard, not attached as a background document that can be changed without vote. o Frequency Bias Setting vs. Frequency Response o RAS events should not be excluded. These events are designed to not have response on the system, even though there may be some primary response. o Paragraph 1 - "each BA has one month" conflicts with the standard that says prior to January 10th or 45 days (1.4 Additional Compliance Information). o 2.a - BPA is assuming the Drafting Team meant 36 mHz. 36 mHz is very small and can be achieve during normal frequency deviations. Point C "within 8 seconds" must be moved to 10 to 12 second range in order to work in WECC. o 2.b - Why so far back on the -16 seconds? o Third from the last paragraph - BPA cannot support a standard that isn't well defined, doesn't adequately spell out the methodology behind the requirements and essentially gives the ERO a blank check to make

Organization	Yes or No	Question 11 Comment
		changes to the standard without a vote. o Second to last paragraph -If you have a poor responding BA control less than they are currently the better responding BA will respond more due to the lower interconnection frequency. This will punish the BAs that have good response and reward those that have poor response, depending on the methodology used to calculate correct frequency bias terms. o Frequency Bias Setting Floor - BPA cannot support a standard that isn't well defined and essentially gives the ERO a blank check to make changes to the standard without a vote. o Frequency Response Obligation and Allocation - BPA cannot support a standard that isn't well defined and essentially gives the ERO a blank check for assigning an FRO to each BA. If this is the method for defining FRO, then it should be included in the requirements section of the standard. However, this section does not spell out how the FRO will be calculated other than that it will be based on the (peak generation + peak load)/2. The full methodology for calculating the FRO must be detailed and put in the standard.
Response: The SDT has modified Attachment A and the Background Document to provide additional clarity concerning the calculation methodology and the reasoning behind the proposed requirements. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that Requirement. The SDT has modified the FRS Form 1 to allow for adjustments. Any adjustment will have to be justified. The SDT has corrected the mistake in Paragraph 1. You are correct concerning the 36 mHZ and this has been corrected. The SDT is only using this to provide a minimum value for selection of events. The SDT has analyzed several different time periods for the Point A, Point B and Point C values. The SDT has chosen the time periods based on this analysis as detailed in Attachment A and FRS Form 1. The SDT is proposing to use -16 seconds in order to account for varying AGC scan rates to obtain an average. The SDT does not believe that there is any requirement presently in place that identifies good or poor responding BAs. The SDT further believes that a BA that is providing proper Frequency Response recognizes the importance and will continue to provide the necessary Frequency Response. Those BAs that are not providing adequate and sustained Frequency Response will be identified through the measure. The SDT disagrees with your comment that this proposed standard gives the ERO a "blank check" to modify the standard. The proposed standard is attempting to bring the Frequency Bias Setting and the natural Frequency Response closer together and not attempting to set a floor. The SDT has modified Attachment A to provide additional clarity concerning the calculation methodologies. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that Requirement.		
SPP Standards Development	No	While we agree that Attachment A is useful, it hasn't quite got to the point where it clearly helps us understand the requirements as well as the calculations and other determinations that must accompany the standard.

Organization	Yes or No	Question 11 Comment
Response: The SDT recognizes this and has responded by revising FRS Form 1 and splitting Attachment A into two documents to better clarify the calculation methodology and the reasoning for the requirements.		
IRC Standards Review Committee	No	Attachment A is useful, but it does not provide a clear understanding of all topics and issues. This is evidenced by the questions and comments the SRC is submitting.
Response: The SDT recognizes this and have responded by revising FRS Form 1 and splitting Attachment A into two documents to better clarify the calculation methodology and the reasoning for the requirements.		
ERCOT	No	Attachment A is useful, but it does not provide a clear understanding of all topics and issues. This is evidenced by the questions and comments the SRC is submitting.
Response: The SDT recognizes this and have responded by revising FRS Form 1 and splitting Attachment A into two documents to better clarify the calculation methodology and the reasoning for the requirements.		
Southern Company	No	We did not want to vote on question 11 - clicked 'NO' in error Comments: Attachment A Comment 1: The initial draft of BAL-003 - Attachment A provides a range of valuable background details and historical information about Frequency Response. However, all of this information is not pertinent to the BAs ability to understand and comply with the Standard. The SDT should consider utilizing the Standards Processes Manual (page 39) which provides a detailed description of various alternatives to an attached supporting document. Document types include References, Guidance, Supplements, Training Material, Procedures, and White Papers. Comment 2: The Standards Processes Manual (page 39) makes clear that supporting "documents may explain or facilitate implementation of the standards but do not themselves contain mandatory requirements subject to compliance review." Draft BAL-003 - Attachment A may be in contradiction to the Manual because it suggests mandatory requirements for the BA. Refer to page one where a statement provides that the BA must, within one month after receiving a listing of official events, assemble its data and calculate a Frequency Response Measure. This obligation is not stated in BAL-003 or the proposed BAL-003-1. The Manual explains that any mandatory requirements must be incorporated into the standard in the standards development process. The SDT should first evaluate whether or not this is a requirement and second, if alternative language may alleviate confusion.
Response: Attachment A has been split in to two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. The SDT has been advised by NERC Legal that an attachment explicitly referenced in a Reliability Standard Requirement is enforceable as part of that		

Organization	Yes or No	Question 11 Comment
Requirement.		
Progress Energy	No	While the attachment provided insite into the distribution of the FRO for each BA, it lacks clarity on whether the interconnection FRO is based on the largest category C event that occurred, or if this event is based on a study. Additionally, if the event is from actual data, what happens if the interconnection is shown to need less response than it currently has due to the response of frequency dependent loads. What happens to BAs that "have only load with no native generation" if they do not meet their FRO? Are they going to be required to meet their FRO through load managmenet schemes?
Response: Attachment A has been split in to two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised for clarity. The SDT believes that a BA that is providing proper Frequency Response recognizes the importance and will continue to provide the necessary Frequency Response. Those BAs that are not providing adequate and sustained Frequency Response will be identified through the measure. The FRO is and will be determined based on the methodology detailed in Attachment A. If A BA does not meet the Requirements then it will be found noncompliant. The proposed standard is setting a minimum Frequency Response but not prescribing a method to meet the requirements. However, the SDT has identified methods of obtaining Frequency Response in the standard.		
NorthWestern Energy	No	A Balancing Authority's frequency response is based upon a "median" value calculated from analyzing multiple events. Frequency response during some of these events is better than others, depending on the system conditions at the time and the amount system loading and unloaded generation online at the time of the event. Given these circumstances a BA's actual response could vary by event (better or worse than median), thus compliance measurement per event to a frequency response obligation based on the median response (over multiple events) could put BA's in non-compliant situations unjustly.
Response: The SDT, in consultation with the NERC Frequency Response Initiative, has performed empirical studies that demonstrate the median is more resilient to data quality problems and statistical outliers.		
Energy Mark, Inc.	No	Comment 20: The document is useful, but it needs a number of modifications to provide a clear understanding of the Requirements.Frequency Bias Setting vs. Frequency Response Section: Comment 21: In bullet 1 the use of the word "storage" is unclear. Comment 22: In bullet 3, The two boxes indicating that the Point A and Point B values are averages should also indicate that the averaging periods for these calculations vary with the scan rate used to collect the data. The correct averaging periods were presented in a table from the NERC Reference Document Understand

Organization	Yes or No	Question 11 Comment
		and Calculating Frequency Response developed by Frequency Response Standard Drafting Team. These scan values used for averaging should be included in the instructions.Frequency Response Obligation and Allocation Section: Comment 23: In the second paragraph of this section there is no supporting analysis that indicates the level of reliability that the selection of “the largest category C event (N-2).” Without such analysis, there is no way to determine the level of reliability that will be supported by this “target contingency protection criteria.” A reliability criterion that supports an unknown level of reliability is no reliability criteria at all. Comment 24: In paragraph four of this section, determination of the “administrative procedure to assign an FRO to each BA for the upcoming year” is removed from the stakeholders and given to the ERO and the NERC RS to determine. This is unacceptable in a stakeholder driven process without more information about how this determination will be made. Comment 25: In paragraph five of this section, an initial method is offered to determine the proportion of total Frequency Response that each BA will use as their FRO. This method is not influenced by the need for Frequency Response in any manner. It therefore, creates perverse incentives for BAs attempting to make decisions concerning Frequency Response and fails to meet the requirement that “A reliability standard shall neither mandate nor prohibit any specific market structure.” This is explained in greater detail later in my comments in response to Questions 16 and 17.Methods of Obtaining Response Section: Comment 26: In the first paragraph, it is suggested that the Frequency Response Obligation could be fulfilled by participating in Reserve Sharing Group (RSG). RSGs were created because of the “non-coincident” nature of the need for Contingency Reserve among BAs. In creating RSGs, all of the BAs in the RSG could reduce the amount of Contingency Reserve that they individually held while still meeting the reliability requirements associated with recovering from disturbances. The savings achieved by reducing individual reserve and sharing reserves provided strong economic incentives to support the infrastructure to create, manage and operate these RSGs. Unlike Contingency Reserves, Frequency Responsive Reserves are always needed on a “coincident” basis because the frequency is the same throughout the interconnection. The strong economic incentives associated with the supply of Contingency Reserves by RSGs do not exist when considering the “coincident” need for Frequency Responsive Reserves. At best, there is only a small reduction in need for reserves on an event by event basis and that small effect is significantly reduced when the averaging period for event measurement is extended over time as the draft standard suggests, one year average measurement period for Frequency Response. Comment 27: In the second paragraph, it is suggested that the problem of obtaining Frequency Response be passed to the RSGs rather than addressing it directly in this standard or in other standards under development. In the distant past, the term “spinning reserve” was weakly related to the amount of Frequency Responsive reserve available. However, in current NERC standards there is no defined relationship between “spinning reserve” and Frequency Responsive Reserve. Therefore, there is no reason to pass this problem to RSGs. However, if an RSG, after investigating the provision of Frequency Response chose to address the problem, there should be no objection to an RSG taking responsibility of its members’ Frequency Response

Organization	Yes or No	Question 11 Comment
		Obligations in a manner similar to a single BA. Comment 28: In the third paragraph, it is suggested that “as long as all BAs within the RSG use the same events for calculating FRM, BAs within the RSG may allocate a portion of their FRM to another RSG participant.” When one considers that there are expected to be over 25 events in the annual calculation, the probability that all BAs in a RSG will have the data available for the same 25 events should be expected to be small, especially for large RSGs. Does selection of events for the RSG members in a manner to insure the same 25 events offer an opportunity to bias the sample?
Response: Comment 20 – Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document titled, “Frequency Response Standard Background Document”, that explains the reasoning behind the requirements. These documents have also been revised to provide clarity. Comment 21 – The SDT has removed the reference to “storage” from the documents. Comment 22 – The SDT agrees and has included averaging periods based on AGC scan rates. Comment 23 – The SDT agrees that further development is needed in this area, and will review this issue during the field trial and provide more definitive analyses. Comment 24 – The SDT has revised Attachment A to clarify the calculation methodology. Comment 25 – The NERC Reliability Standards do not necessarily dictate “how” Requirements are satisfied. A market can be created by a region, sub-region, ISO, RTO or other entities as appropriate to facilitate compliance however the NERC Reliability Standards do not establish markets. Comments 26 & 27 & 28 – The SDT appreciates these observations and has taken these comments under consideration including modifying the standard regarding RSGs.		
FMPP	No	It is useful, but Attachment A is not clear.
Response: Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document titled, “Frequency Response Standard Background Document”, that explains the reasoning for the requirements. These documents have also been revised for clarity.		
American Electric Power	No	As stated earlier, attempting to follow requirement(s) within multiple versions of the same standard would be very difficult. In addition, more examples should be provided.
Response: Requirement R5 has been inserted back into this version of the draft standard and should eliminate the concern of trying to operate using multiple versions of the same standard. This standard will replace all versions of BAL-003 currently in effect. The SDT has also revised Attachment A and FRS Form 1 to provide clarity.		

Organization	Yes or No	Question 11 Comment
Duke Energy	No	Attachment A is useful, however R2 of the standard references a "calculation methodology detailed in Attachment A" and it isn't clear to us what part of Attachment A is the methodology. Also, in Attachment A the term "Interconnection Frequency Response Obligation" is used, but the definition of FRO says it's a BA value, so that's inconsistent. Overall, we agree that the document is helpful; however, we do believe additional explanation is necessary for Requirement 2. It appears that the responsibility for identifying Frequency Bias Setting is being removed from the Balancing Authority. There is an implied obligation that the ERO will determine the Frequency Bias Setting but it is not stated explicitly. Under the proposed standard, who has the responsibility for determining the Frequency Bias Setting?
Response: The SDT has also revised Attachment A and FRS Form 1 to provide clarity. The SDT is not suggesting that the ERO determine the Frequency Bias Settings. The SDT has modified the language in Requirement R2 to provide further clarity as to the role of the ERO. The Requirement now reads "Each Balancing Authority not participating in Overlap Regulation Service shall implement the Frequency Bias Setting (fixed or variable) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control."		
Patterson Consulting, Inc.	No	The historical, contextual, and instruction information is valuable and needs to be associated with this standard. This material should not be included in Attacment A, though, as described in previous responses. In addition, there are inconsistent use of definitions and terms in the document that should be corrected.
Response: Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document titled, Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		
South Carolina Electric and Gas	Yes	It would be helpful to have a heading to transition from the criteria section to the reasoning section. Also, the title of attachment A should include "Frequency Response" before "Background Document."
Response: The SDT thanks you for your affirmative response and clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		
NIPSCO	Yes	Not sure if all the requirements need to be explained, we'll wait for future postings.

Organization	Yes or No	Question 11 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		
Westar Energy	Yes	The attachment should be updated as the proposed standard is revised and the standard becomes effective and field test results are available. The typical frequency response curve with points A,B and C should be included and therefore part of the standard.
Response: The SDT thanks you for your affirmative response and clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity. The SDT will evaluate and determine if additional modifications are necessary prior to posting for industry approval. The frequency curve points A, B and C are identified in FRS Form 1 and therefore are part of this standard.		
Manitoba Hydro	Yes	While Attachment A is useful, it could be improved by adding a graph to better illustrate Point A and C and the 4 second data sampling rate.
Response: The SDT thanks you for your affirmative response and clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		
Seattle City Light	Yes	
EKPC	Yes	
ENBALA Power Networks	Yes	
SERC OC Standards Review Group	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 11 Comment
Independent Electricity System Operator	Yes	
Santee Cooper	Yes	
LG&E and KU Energy	Yes	
Arizona Public Service Company		AZPS agrees it is useful, however, more clarity of how the FRO is determined and how the FRO differs from the FRM.
Response: The SDT thanks you for your comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity. The FRO is the minimum amount of Frequency Response needed to comply with this standard. The FRM is the measure of the Frequency response provided during an event.		
Alberta Electric System Operator		AESO suggests that this document should provide a clear description and discussion of the concerns, response measures at different aspects or time frames of frequency response (inertial response, governor response, AGC response; arresting deviation and settled deviation),and should provide technical evidence or reasons why the proposed standard can address the related concerns.
Response: The SDT thanks you for your clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		
ISO New Engand Inc.		Attachment A is useful, but it does not provide a clear understanding of all topics and issues.
Response: The SDT thanks you for your clarifying comment. Attachment A has been split into two documents. Attachment A now provides the calculation methodology to be used for the standard and a new document, titled, "Frequency Response Standard Background Document", that explains the reasoning for the requirements. These documents have also been revised to provide clarity.		

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		

12. ***The proposed standard requires the use of FRS Form 1 for calculating a Balancing Authority's FRM. Do you agree with the SDT that this is the proper method to calculate its FRM? If not, please explain in the comment area and if possible provide an alternate method to calculate FRM.***

Summary Consideration: Several of the commenters agreed that the calculation in FRS Form 1 is the proper method for calculating the FRM. Many commenters expressed concern that the FRM calculation method was simplistic, did not capture all contributing factors, and that use of the median value may result in a determination of noncompliance for otherwise compliant conditions. Regarding FRS Form 1, many calculation errors were identified and several commenters indicated that the information provided was neither clear nor complete. There was general consensus for conducting a field trial during which consideration of other statistical methods will be evaluated by the SDT. A few commenters believe that the 1% of peak formula currently in use should be maintained. Another comment indicated that certain events including contingent Balancing Authority events should not be used for the calculation. One commenter indicated more study is needed to determine how to account for energy flowing across a Balancing Authority's Area since this flow could affect frequency response. Concern was also expressed indicating there is not a reliability basis or replacement for addressing the AGC Frequency Response phase out approach for Requirement R5.

In response to industry comments the SDT has revised FRS Form 1 (including calculations) to allow for adjustments to the calculations. The SDT affirms that the median is the preferred measure for eliminating statistical outliers which have a tendency to skew analysis results. Other statistical methods will be considered by the SDT during the field trial. The SDT agrees there needs to be a floor Frequency Response Setting threshold however the current 1% of peak of peak load/generation threshold is causing many Balancing Authorities to over bias, causing unnecessary ACE and frequency undulations. The drafting team is proposing a phased approach for reducing the Frequency Bias Setting value to less than 1% of peak load/generation for Balancing Authorities with actual Frequency Response is currently less than this value. This approach is detailed in Attachment B.

Organization	Yes or No	Question 12 Comment
Bonneville Power Administration	No	RAS events and Contingent BA events shouldn't be used in the calculation. The FRS Form 1 has a basic flaw that needs correction. For Balancing Authorities that have frequency response wheeled across them by other BAs (for example, with BPA, any contingency that occurs in the south will have frequency response from BCHydro wheeled across it) and the associated losses will show as less frequency response by the BA that is being wheeled across. BPA recommends that the generation and load be measured, primarily generation, in order to find the frequency response of the BA. Since few, if any, BAs directly measure their total load, the calculated load will have the same issue due to the responses wheeling across the BA (load is generally calculated as total generation minus total interchange). Therefore, more study needs to be done to determine how to account for the energy flowing across a BA.
Response: The drafting team has taken the suggestion to exclude RAS events for frequency response analysis and will study this further should there be a need to incorporate more events to perform frequency response analysis.		

Organization	Yes or No	Question 12 Comment
The method of analyzing a BA response is formed on a net metered basis to obtain the BA response. The response is not summed across intermediate BAs for loss consideration and ultimate delivery of energy. In the case of Bias the deviation from present metering is an indication of response and load change within the BA as noted in the response. Frequency response could be calculated by measuring each generator and load bus change but then there are distribution losses reflected in the numbers. The generally accepted method presently assumes that change in loss for the frequency response MW delivery is not significant when delivered by many sources.		
SPP Standards Development	No	We do not necessarily agree that it does. Please see our response to Question 1.For the 2010 survey NERC provided the Points A and Points B for the listed events in the provided spreadsheet. FRS Form 1 does not contain that information, only the delta frequency. Please include the Point A and Point B frequencies for the SEFRD events in FRS Form 1.
Response: Please refer to our response for Question 1. The drafting team has revised FRS Form 1 and Points A and B values are calculated in FRS Form 2 and shown in FRS Form 1. These values will differ for each BA based on readings at the BAs location rather than a specific location in the interconnection.		
IRC Standards Review Committee	No	It is one method, but not necessarily the only proper method. Not all existing methods need to be replaced. The SRC suggests scan data could be used so that different metrics can be evaluated.
Response: The drafting team agrees with the IRC Standards Review committee conclusion that the field trial evaluation will support the proper selection of the metric utilized. The SDT believes there is a need for a common methodology for evaluating Frequency Response.		
ERCOT	No	It is one method, but not necessarily the only proper method. Not all existing methods need to be replaced. The SRC suggests scan data could be used so that different metrics can be evaluated.
Response: The drafting team agrees with the IRC Standards Review committee conclusion that the field trial evaluation will support the proper selection of the metric utilized. The SDT believes there is a need for a common methodology for evaluating Frequency Response.		
ISO New Engand Inc.	No	It is one method, but not necessarily the only proper method.
Response: The drafting team agrees with the IRC Standards Review committee conclusion that the field trial evaluation will support the proper selection of the metric utilized. The SDT believes there is a need for a common methodology for evaluating Frequency Response.		
Kansas City Power & Light	No	This method is too simplistic and does not take into account normal statistical variations in metering accuracy and resolution for generation and tie-lines, does not take into account the natural variations of generation due to mechanical variations, and does not take into account the impact of load control actions on generation. Without taking these variations into account, the outcome is the wild calculation results that have been seen in the current submissions by BA's that should be an indication that the method needs considerable work to be considered useful.

Organization	Yes or No	Question 12 Comment
Response: The drafting team disagrees that the method needs to address SCADA support concerns cited. There should be a documented reason for each error which can be excluded. The field trial evaluation will identify errant calculations and any need for further revision.		
Progress Energy	No	Progress Energy believes you can, and should calculate a frequency response for BAs with the contingency also. We are also not certain that a strict median response should be used as it provides opportunity for BAs to perform moderately most of the year and make up for it with a few days slightly above their desired median target when they should take measures to hit their target every time within a standard deviation tolerance (excluding outliers)
Response: We thank you for your support. The SDT, in consultation with the NERC Frequency Response Initiative, has performed empirical studies that demonstrate the median is more resilient to data quality problems and statistical outliers. The SDT believes that this measurement methodology using the median value is the most appropriate method at this time.		
NorthWestern Energy	No	A Balancing Authority's frequency response is based upon a "median" value calculated from analyzing multiple events. Frequency response during some of these events is better than others, depending on the system conditions at the time and the amount system loading and unloaded generation online at the time of the event. Given these circumstances a BA's actual response could vary by event (better or worse than median), thus compliance measurement per event to a frequency response obligation based on the median response (over multiple events) could put BA's in non-compliant situations unjustly. Page 2 implies that there is currently too much frequency response based on the 1% of peak demand method of establishing frequency bias. Even though NWE does not use the 1% method, NWE feels that the 1% minimum has been a tried and true method of providing frequency response in the Western Interconnection.Without the 1% minimum (and BA's using a natural response less than the 1%), the total interconnection frequency response would decrease according to research. This would lead to decreased interconnection bias, causing other operational issues, such as lower L10 values and possible CPS2 compliance factors.
Response: The drafting team agrees that calculated frequency response varies from event to event. This is because there are multiple Balancing Authorities interconnected and each BA has a small frequency response contribution compared to the variation in its load and generation experienced at any given moment. This is why the drafting team is proposing to use the median value of events selected during the year as a measure of "average" response. The median is the preferred measure to eliminate population statistical outliers which have tendency to skew results. The SDT agrees the Interconnections possess sufficient frequency response. The drafting team is proposing testing using a bias setting value of less than 1% for BAs with frequency response that is less than the 1% value currently calculated in order to better match the natural response. The drafting team agrees there needs to be a floor threshold however the current 1% threshold is causing many BAs to over-bias, resulting in ACE and frequency undulations. Please identify the research indicating control problems would occur using a minimum bias setting that is less than 1%.		

Organization	Yes or No	Question 12 Comment
The SDT agrees bias setting changes may impact CPS compliance calculation which is why the drafting team is proposing field testing using small, incremental changes to the bias setting. Research by Nathan Cohn (Control of Generation and Power Flow on Interconnected Systems) indicates improved AGC and frequency performance can be realized by better matching bias setting to frequency response; which should improve CPS compliance.		
Energy Mark, Inc.	No	Comment 29: I agree that a method similar to the one suggested can be used to calculate the BA's FRM. However, there are a number of errors in the suggested FRS Form 1.Data Entry Tab: Comment 30: The calculation of SEFRD in column G is incorrect for events marked as Internal Contingency in Column I. This calculation must also include the change in internal generation due to the Internal Contingency. This adjustment must either be explained in the "Balancing Authority FRS Form 1 Background and Instructions" or the calculation must be modified using a column added to the NERC FRS Form 1 (between column J and K) to include the size of the Internal Contingency in MW. Comment 31: The calculation in cell L22 is incorrect because it includes the incorrect calculations from the lines that indicate Internal Contingency. If the calculation in column G is corrected this cell will also be corrected. Comment 32: The calculation in cell L23 is incorrect because it includes the incorrect calculations from the lines that indicate Internal Contingency. If the calculation in column G is corrected this cell will also be corrected. Comment 33: The calculation in cell L24 is incorrect. It provides the intercept of the linear regression for the Frequency Response using the Intercept function. It should provide the slope of the regression of the change in NAI from Column F to D regressed against the change in Frequency, Column B, using the LINEST function with a forced fit through the origin, using the function y = mx. The correct value for the sample data in the NERC FRS Form 1 is -24.7, not -16.2. Comment 34: The calculation in cell L27 is incorrect. It provides the intercept of the linear regression for the Frequency Response using the Intercept function. It should provide the slope of the regression of the change in NAI from Column F to D regressed against the change in Frequency, Column B, using the LINEST function with a forced fit through the origin, using the function y = mx. The correct value for the sample data in the NERC FRS Form 1 is -22.5, not -33.9. Comment 35: Cell M19 and M31 should read "...Frequency Response Obligation...", not "...Frequency Requirement Obligation..." Comment 36: The regression methods described in Comments 33 & 34 above provide the best method to calculate FRM. The linear regression method described is the only method of those suggested that properly weights the data with respect to its influence on the value of FRM. Using the median fails to weight the data at all. Using simple averaging weights the smaller events more than the larger events in the sample as compared to their influence on the best estimate for FRM.

Organization	Yes or No	Question 12 Comment
Response: Comments 29,31, 32, 33, 34 and 35 – FRS Form 1 has been revised and corrected Comments 30 – FRS Form 1 has been extensively revised and instructions for its use have be clarified. Comment 36 – The SDT is evaluating several calculation methodologies. The SDT will propose the most suitable method in its final draft of this standard.		
American Electric Power	No	The FRS Form 1 is actually calculating prior performance results from identified events to determine future measure. The calculation method to determine a BA's FRM still is not capturing all contributing factors that occur in real time and have an impact at time of event occurrence to determine frequency response performance to be measured. The calculation method and FRM needs to be more complete to include all of these contributing factors such as magnitude of actual generation on line at time of occurrence that is capable of governor & AGC response, actual generator loading, scheduled interchange imports to balance or meet load demand, etc. The calculation method and FRM also needs to be more dynamic to allow inclusion of these variable contributing factors to be able set proper measure and identify lack of performance to actually address the issue, if there truly is one. There needs to be some form of measure at the actual generator level. Measuring a BA's aggregate response will not address contributing generators having negative governor or AGC frequency response, and puts the entire burden on the BA when the performance issue to be resolved is more at generator level. There appears to be no reliability basis or replacement for addressing the AGC frequency response phase out approach for R5 implementation plan. Without a reliability results based study to support this approach, it appears on the surface that there is the potential to lose some of the AGC part of response. Variable energy resources that are non-responsive must also be addressed in the overall calculation and measure. Because the electric industry has evolved with unbundling of generation/transmission and implementation of energy markets, there needs to be an ancillary service component for frequency response to address the factor of independent players that impact the lack of or negative frequency response issue. When impacting entities have financial factors that conflict with reliability intent, the reliability performance process can be compromised and made more difficult to achieve.
Response: FRS Form 1 has been revised. The dynamic measure as suggested implies the BA should have a dynamic response incorporated into its frequency bias setting as a variable component. The SDT believes that the current 1% of peak of peak load/generation threshold is causing many Balancing Authorities to over bias, causing unnecessary ACE and frequency undulations. The drafting team is proposing a phased approach for reducing the Frequency Bias Setting value to less than 1% of peak load/generation for Balancing Authorities with actual Frequency Response that is currently less than this value. This approach is detailed in Attachment B. The drafting team welcomes the initiative of companies to offer a NAESB solution for ancillary services which is beyond the scope of this SAR.		

Organization	Yes or No	Question 12 Comment
Duke Energy	No	Other factors need to be considered and incorporated in the calculation. See comments to 1 and 2 above.
Response: Please see our response to Questions 1 and 2. FRS Form 1 has been revised and the drafting team will list specific reasons for revisions and event exclusion.		
Patterson Consulting, Inc.	Yes	Pending modifications based on results from the field test and subsequent operation under the new standard, FRS Form 1 is a good start for calculating a Balancing Authority's Frequency Response Measurement and Frequency Bias Setting.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
South Carolina Electric and Gas	Yes	The form must have clear instructions on its use and meanings of the terms.FRS Form 1 and Instructions should be included as an attachment to the BAL-003-1 standard.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
Santee Cooper	Yes	The form must have clear instructions on its use and meanings of the terms. The form should include the ability to take into account changes in metered non-conforming loads.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised to allow for adjustments such as non-conforming load.		
LG&E and KU Energy	Yes	The form must have clear instructions on its use and meanings of the terms.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
FirstEnergy	Yes	Although the method seems acceptable in theory, the results of the field test will be needed to validate the methodology.
Response: We thank you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 12 Comment
SERC OC Standards Review Group	Yes	The form must have clear instructions on its use and meanings of the terms.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
ENBALA Power Networks	Yes	ENBALA also believes that including an additional metric, such as the metric suggested in the recent Lawrence Berkeley National Laboratory of a nadir-based frequency response, would be useful in assessing the current inertial response capabilities and level of risk for under-frequency load shedding.
Response: We thank you for your affirmative response and clarifying comment. The SDT will consider your suggestion during the field trial.		
NIPSCO	Yes	Seems straightforward compared to other methods
Response: We thank you for your affirmative response and clarifying comment.		
EKPC	Yes	The form should include clear instructions for use and clear definitions for terms.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
Manitoba Hydro	Yes	Although it can be difficult for some events to determine the NIA and load values for the A & B points(due to significant signal variations), this is still the best known method at this time.
Response: We thank you for your affirmative response and clarifying comment. FRS Form 1 has been revised.		
Seattle City Light	Yes	
We Energies	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 12 Comment
FMPP	Yes	
Arizona Public Service Company	Yes	
Midwest ISO Standards Collaborators	Yes	
Independent Electricity System Operator	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Alberta Electric System Operator		The standard uses median of multiple SEFRD for the calculation of FRM, which is a reasonable method. The AESO suggests NERC considers the alternative "zero-cross linear regression" method for the FRM calculation. The key difference of "zero-cross linear regression" is that it puts more weight on events with bigger frequency deviation. As the standard is to address the concerns related with large frequency error that could cause UFLS, the more weight put on larger events seems more reasonable.
Response: We thank you for your input and suggested method will be considered during the field trial.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please see our response to Question 17.		

13. ***The proposed standard requires the use of FRS Form 1 for calculating a Balancing Authority's Frequency Bias Setting. Do you agree with the SDT that this is the proper method to calculate its Frequency Bias Setting? If not, please explain in the comment area and if possible provide an alternate method to calculate Frequency Bias Setting.***

Summary Consideration: Many of the commenters agreed with requiring the use of FRS Form 1 for calculating a Balancing Authority's Frequency Bias Setting. Most commenters agreed with the concept but expressed concern that FRS Form 1 had errors, incorrect calculations, did not provide consideration for variable bias, and instructions were vague. Some commenters indicated that the methodology was too simplistic and use of the median value is not an adequate approach. Comments were also received suggesting the current 1% of peak methodology is a proven method that should be maintained and each Balancing Authority should be allowed to determine its Frequency Bias Setting. One commenter suggested the FRO value should not be considered when determining the Frequency Bias Setting. Another commenter suggested gradually lowering the Frequency Bias Setting floor threshold over several years to assess the associated reliability impacts. The SDT agrees and implemented this approach. Initially the FRM will be computed to 0.8% of the Balancing Authority's forecasted peak load or generation. A recommendation was provided to estimate the Frequency Bias Setting using a linear slope approach with a least square fit method. The SDT will assess this method as part of the field trial. Observations provided include field testing must validate the methodology and that the methodology should include two measures (AGC and interchange) for identifying lack of frequency response.

In response to industry comments the SDT has revised FRS Form 1 to allow adjustments for known variables that will impact the measure. One commenter noted that Requirement R2 states that the ERO will provide the Frequency Bias Setting for each Balancing Authority whereas FRS Form 1 specifies a calculation to obtain a value which the ERO is not required to review or use. The SDT has modified the requirement to address this process reporting and implementation concern.

Organization	Yes or No	Question 13 Comment
Bonneville Power Administration	No	BPA thinks that the Form can be used as a tool, but the results shouldn't be the required Frequency Bias setting. Each individual BA should be allowed to set their own. Also, this shows no consideration for variable bias. Variable bias changes greatly during a contingency and this should be considered.Please see comments to number 12.
Response: The SDT agrees that measurement of individual generator's performance would produce a more accurate measure of Primary Frequency Control and that the SDT had not considered losses within a BA's system due to frequency response of other BA's frequency response flowing through their system. This could indeed have some effect on the accuracy of the measure when using Interchange Actual for the measure. The SDT agrees that variable bias, based on real time conditions (up and down headroom) of on line generators and other frequency responsive devices, will produce the most accurate value for the bias setting if the BA implements a program that will accurately estimate Primary Frequency Control from each of its generators or other frequency responsive devices and account for load dampening. Form 1 could still be used as a confirmation of general performance and to consistently measure every BA to the same events for comparison to the Interconnection's performance as a whole. If the BA were willing to measure performance of each generator and other frequency responsive devices to the same list of events as an additional measure, this could be used in the field trial to determine the magnitude of the measurement error of Form 1.		

Organization	Yes or No	Question 13 Comment
The SDT would like to move the industry to accept the use of variable bias as the superior method for setting the Bias in the ACE equation as long as the BA meets its minimum FRO and that the variable bias result matches actual Primary Frequency Control performance within some tolerance. A BA should not be allowed to use a variable bias just to inflate their L10 values for CPS2 compliance.		
SPP Standards Development	No	We do not necessarily agree that it does. Please see our response to Question 1.Given the disclaimers on page 7 of the FRS Form 1 instructions under Data Values, do the BAs have the discretion to change data in Form 1 if it doesn't match the data they recorded on their system?
Response: FRS Form 1 has been revised to allow adjustments for known variables that will impact the measure. The field trial will validate the accuracy of the measure and identify problems using Interchange Actual. The BA can adjust the t (0) event time to align with their frequency data but they should not change their data. Adjustments should be made in the columns provided in the revised FRS Form 1.		
IRC Standards Review Committee	No	It appears to be one acceptable method, but not all the calculations done through the use of the form are clearly described. Further, it says that the Frequency Bias Setting will be based upon the FRM, but it doesn't say how that will be done.
Response: FRS Form 1 has been revised to be clearer. Initially the FRM will be compared to 0.8 % of the BA's forecasted peak load or generation. The Bias setting will be based on the larger value. BA's will continue to be able to use a variable bias.		
ERCOT	No	It appears to be one acceptable method, but not all the calculations done through the use of the form are clearly described. Further, it says that the Frequency Bias Setting will be based upon the FRM, but it doesn't say how that will be done.
Response: FRS Form 1 has been revised to be clearer. Initially the FRM will be compared to 0.8 % of the BA's forecasted peak load or generation. The Bias setting will be based on the larger value. BA's will continue to be able to use a variable bias.		
Kansas City Power & Light	No	This method is too simplistic and does not take into account normal statistical variations in metering accuracy and resolution for generation and tie-lines, does not take into account the natural variations of generation due to mechanical variations, and does not take into account the impact of load control actions on generation. Without taking these variations into account, the outcome is the wild calculation results that have been seen in the current submissions by BA's that should be an indication that the method needs considerable work to be considered useful.
Response: When the BA's bias setting closely matches natural Primary Frequency Control, L10 and CPS1 and CPS2 will more accurately measure the BA's ACE impact on the Interconnection's frequency. This may also cause greater difficulty maintaining CPS1 and CPS2 compliance. The sample size of identified events is intended to address BA performance variability concerns. FRS Form 1 has been revised to account for known variables that will impact the measure. The SDT believes that when actual BA Primary Frequency Control		

Organization	Yes or No	Question 13 Comment
improves, the measure will be more consistent and useful.		
Progress Energy	No	The FRO should not be part of the determination of the bias setting unless you are actually going to respond by the FRO value. BAs should be trying to get their FRC <= FRO, but not biasing by the FRO. The bias has no effect on the FRC. Progress Energy also think the % of projected peak requirement should be removed now.
Response: The SDT agrees that the % of projected peak requirement has been contributing to Secondary Frequency Control problems and has determined that a phased-in approach is the preferred method of eliminating this requirement. The FRO is not intended to be the BA's bias setting unless the BA's actual Primary Frequency Control is equal to the BA's FRO and meets the minimum of the 0.8% of the BA's forecasted Peak Load or Generation.		
NIPSCO	No	Not sure, It appears that the FR is about 1/2 of the freq bias in the East Int. I think that the bias could be brought down gradually over several years while monitoring system frequency for reliability.
Response: The SDT agrees and the standard has been modified to reflect your concern.		
NorthWestern Energy	No	Page 2 implies that there is currently too much frequency response based on the 1% of peak demand method of establishing frequency bias. Even though NWE does not use the 1% method, NWE feels that the 1% minimum has been a tried and true method of providing frequency response in the Western Interconnection.Without the 1% minimum (and BA's using a natural response less than the 1%), the total interconnection frequency response would decrease according to research. This would lead to decreased interconnection bias, causing other operational issues, such as lower L10 values and possible CPS2 compliance factors. A Balancing Authority's frequency response is based upon a "median" value calculated from analyzing multiple events. Frequency response during some of these events is better than others, depending on the system conditions at the time and the amount system loading and unloaded generation online at the time of the event. Given these circumstances a BA's actual response could vary by event (better or worse than median), thus compliance measurement per event to a frequency response obligation based on the median response (over multiple events) could put BA's in non-compliant situations unjustly.
Response: The drafting team agrees that calculated frequency response varies from event to event. This is because there are multiple Balancing Authorities interconnected and each BA has a small frequency response contribution compared to the variation in its load and generation experienced at any given moment. This is why the drafting team is proposing to use the median value of events selected during the year as a measure of "average" response. The median is the preferred measure to eliminate population statistical outliers which have tendency to skew results. The SDT agrees the Interconnections possess sufficient frequency response. The drafting team is proposing testing using a bias setting value of less than 1% for BAs with frequency response that is less than the 1% value currently calculated in order to better match the natural response. The drafting team agrees there needs to be a floor threshold however the current 1% threshold is		

Organization	Yes or No	Question 13 Comment
causing many BAs to over-bias, resulting in ACE and frequency undulations. Please identify the research indicating control problems would occur using a minimum bias setting that is less than 1%. The SDT agrees bias setting changes may impact CPS compliance calculation which is why the drafting team is proposing field testing using small, incremental changes to the bias setting. Research by Nathan Cohn (Control of Generation and Power Flow on Interconnected Systems) indicates improved AGC and frequency performance can be realized by better matching bias setting to frequency response; which should improve CPS compliance. The SDT agrees bias setting changes may impact CPS compliance calculation which is why the drafting team is proposing field testing using small, incremental changes to the bias setting. Research by Nathan Cohn (Control of Generation and Power Flow on Interconnected Systems) indicates improved AGC and frequency performance can be realized by better matching bias setting to frequency response; which should improve CPS compliance. The SDT fails to see the implication that there is too much frequency response based on the 1% of peak demand method of establishing frequency bias. The bias setting will not increase or decrease Primary Frequency Control. It will only impact the measure of ACE and the resulting Secondary Control of the BA. The 1% minimum requirement was appropriate in the past when BA's Primary Frequency Control was nearly equal to 1% of the forecasted peak load or peak generation. Form 1 and this revision to BAL-003 would still require that the Bias setting in the ACE equation be equal to or greater than the natural Primary Frequency Control of the BA with a minimum value of 0.8% of the BA's forecasted peak load or peak generation. When the BA's bias setting closely matches natural Primary Frequency Control, L10 and CPS1 and CPS2 will more accurately measure the BA's ACE impact on the Interconnection's frequency. This may also cause greater difficulty maintaining CPS1 and CPS2 compliance. The sample size of identified events is intended to address BA performance variability concerns. The field trial results should prove if this is a correct assumption.		
Energy Mark, Inc.	No	Comment 37: My initial comments associated with calculation of the Frequency Bias Setting are included in my comments 3, 4, 5, 6, 30, 31, 32, 33, 34 and 36. Comment 38: The determination of the Frequency Bias Setting using a median or mean value provides an incorrect weighting of the individual SEFRD measurements to correctly determine the Frequency Bias Setting. The Frequency Bias Setting as used in the ACE Equation represents a linear function of Frequency Response to frequency error. The best estimate of the Frequency Bias Setting from this SEFRD data is the slope of the line through the origin using a least-squares fit. Any other method of determining the Frequency Bias Setting will improperly weight the individual data points contribution to the error thus providing a poorer estimate of the true value of Frequency Response.
Response: Comment 37 - Please refer to our response to the comments noted. Comment 38 - Once events have been identified and data collected the SDT can and will use multiple methods of determining the best selection of a bias setting for BA's using a fixed bias. The SDT will include your recommended method as one that is considered.		
FMPP	No	It would be better to define significant and let the BA exclude any events that meet this definition, since each BA will be ramping differently. Since SEFRD is defined as the individual sample of event data from a Balancing Authority which represents the change in Net Actual Interchange (NIA), divided by the change in frequency, expressed in MW/0.1Hz, whenever a BA includes an event with a "significant" change in NIA due

Organization	Yes or No	Question 13 Comment
		to a large interchange schedule ramp, the FRM is totally skewed, and should not be included. If other events are available means that if other events are not available then an entity's compliance is going to be based on an event or events that has been skewed for the BA by significant interchange schedule ramp.
Response: FRS Form 1 has been revised to account for known variables that will impact the measure. The SDT believes that when actual BA Primary Frequency Control improves, the measure will be more consistent and useful. Using identified events and measuring every BA's performance during these events will provide comparison of all BA's performance to the Interconnection's performance as a whole.		
American Electric Power	No	There should be two measures to identify lack of frequency response: A calculation and measure for the AGC part of frequency response based on actual load and generation on line at time of occurrence that is variably adjusted and measured, while also accounting for interchange imports to balance. Today's frequency bias setting does not really address the governor response issue. There also needs to be some form of generator governor response calculation and measure that starts with a base foundation of droop setting/relative governor response and is adjusted accordingly. As WECC appears to have shown in its studies, there would be excessive governor response based on current droop setting if governors responded as they are expected. This could be an indicator that governor response measure should only be a percentage of this droop, which protects the generator. Different types of generators and their characteristics must also be factored in.Since there does not appear to be a performance issue with the Standards involving CPS, we do not believe the CPS Bounds L10 values should be reduced.
Response: FRS Form 1 has been revised to account for identified variables in measuring Primary Frequency Control. The SDT agrees that measuring generator governor response and Primary Frequency Control would be beneficial for determining proper delivery of frequency response. The SDT also agrees that generator governor and droop settings will impact Primary Frequency Control but this concern is outside the scope of this project and a separate SAR will be required to address governor settings. The SDT is not aware of any WECC studies indicating excessive governor response based on current droop settings if governors responded as they are expected. The industry nominal droop setting is 5% and this level of performance should limit transmission flows across specific elements unless the planning process does not account for this flow during contingencies. If Primary Frequency Control is not evenly distributed across the Interconnection or there is not participation in Primary Frequency Control by all generators with sufficient regulation margin, elements of the transmission system can become overloaded during a contingency. The SDT believes that when the Bias setting in the BA's ACE equation closely matches the Primary Frequency Control of the BA, then the ACE will accurately measure the BA's impact on Interconnection frequency through the CPS 1 and CPS 2 measures. If a BA has very low Primary Frequency Control and resulting lower Bias setting, the L10 value will change also.		
Duke Energy	No	Other factors need to be considered and incorporated in the calculation. See comments to 1 and 2 above.
Response: FRS Form 1 has been revised to account for known variables.		
Patterson Consulting, Inc.	Yes	Requirement 2 states that the ERO will provide the Frequency Bias Setting for each Balancing Authority. While FRS Form 1 makes a calculation, the requirement does not require the ERO to review or use the FRS Form 1 value. Otherwise, pending modifications based on results from the field test and subsequent operation

Organization	Yes or No	Question 13 Comment
		under the new standard, FRS Form 1 is a good start for calculating a Balancing Authority's Frequency Response Measurement and Frequency Bias Setting.
Response: The SDT has modified the requirement to address the reporting and implementation process of the bias setting.		
South Carolina Electric and Gas	Yes	The form must have clear instructions on its use and meanings of the terms. FRS Form 1 and Instructions should be included as an attachment to the BAL-003-1 standard.
Response: The SDT agrees and has revised Form 1 with instructions to provide clarity in using the form.		
Santee Cooper	Yes	The form must have clear instructions on its use and meanings of the terms.
Response: The SDT agrees and has revised Form 1 with instructions to provide clarity in using the form.		
MRO's NERC Standards Review Subcommittee	Yes	We agree that using Points A and B is correct and the calculations in the spreadsheet are correct.
Response: Thank you for your comment.		
LG&E and KU Energy	Yes	The form must have clear instructions on its use and meanings of the terms.
Response: The SDT agrees and has revised Form 1 with instructions to provide clarity in using the form.		
Midwest ISO Standards Collaborators	Yes	We agree that using Points A and B is correct and the calculations in the spreadsheet are correct.
Response: Thank you for your comment.		
FirstEnergy	Yes	Although the method seems acceptable in theory, the results of the field test will be needed to validate the methodology.
Response: The SDT agrees. The field test will utilize the method to test the measure.		
SERC OC Standards Review Group	Yes	The form must have clear instructions on its use and meanings of the terms.
Response: The SDT agrees and has revised Form 1 with instructions to provide clarity in using the form.		

Organization	Yes or No	Question 13 Comment
EKPC	Yes	The form should include clear instructions for use and clear definitions for terms.
Response: The SDT agrees and has revised Form 1 and included instructions to provide clarity in using the form.		
We Energies	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
Independent Electricity System Operator	Yes	
Arizona Public Service Company	Yes	
ENBALA Power Networks	Yes	
Westar Energy	Yes	
Alberta Electric System Operator		The AESO finds it difficult to comment as it is not clear how the FRO is determined.
Response: The revised instructions clarify the method for determining the FRO.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response for Question 17.		

14. *The SDT has provided a document (FRS Form 1 Instructions) describing how to use FRS Form 1 for calculating FRM and Frequency Bias Setting. Do you agree with the SDT that this document provides a clear understanding of how to use the form? If not, please explain in the comment area.*

Summary Consideration: Several of the commenters did not agree that FRS Form 1 instructions provide a clear understanding of how to use the form. The majority of commenters indicated that the instructions were incomplete, unclear, required better definitions, lacked variable bias information, technically incomplete and mainly provided background information. In response to industry comments the SDT has revised FRS Form 1 instructions and removed the background information.

Organization	Yes or No	Question 14 Comment
MRO's NERC Standards Review Subcommittee	No	On page 5 and 6, graphics appear to be missing. This document really provides no instructions but rather explanations and background material for measuring frequency events. Instructions would be more along the lines of step 1: Enter date in box, etc.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
Midwest ISO Standards Collaborators	No	On page 5 and 6, graphics appear to be missing. This document really provides no instructions but rather explanations and background material for measuring frequency events. Instructions would be more along the lines of step 1: Enter date in box, etc.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
FirstEnergy	No	On page 5 and 6, graphics appear to be missing. This document really provides no instructions but rather explanations and background material for measuring frequency events. Instructions would be more along the lines of step 1: Enter date in box, etc.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
We Energies	No	On page 5 and 6, graphics appear to be missing. This document really provides no instructions but rather explanations and background material for measuring frequency events. Instructions would be more along the lines of step 1: Enter date in box, etc.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
LG&E and KU Energy	No	We believe the FRS form 1 instructions should be improved by better defining the terms used and improving the overall layout of the form. The document provided should be corrected so that all figures are viewable

Organization	Yes or No	Question 14 Comment
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
SERC OC Standards Review Group	No	We believe the FRS form 1 instructions should be improved by better defining the terms used and improving the overall layout of the form. Fiqure 1 in Section B of the FRS Form 1 Instructions document should be corrected so that it is viewable.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
South Carolina Electric and Gas	No	We believe the FRS form 1 instructions should be improved by better defining the terms used and improving the overall layout of the form. The document provided should be corrected so that all figures are viewable.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
Bonneville Power Administration	No	There is no explanation for variable bias. If the suggesting from tab 2 is that a monthly average should be used then this grossly misrepresents the amount of variable bias that is used during a contingency. For example: BPAs monthly average ranges from-150 to -160, but during a contingency it can be in the -400 to -500 range. Figure 1 does not show up so it cannot be determined if BPA agrees with Points A, B and C. Averaging the pre and post data with 16 seconds and 34 seconds, respectively, will cause the calculations to be skewed with some generator response, some tertiary response, etc. We do agree, if Figure 1 appears, that this does spell out how to use the form, BPA just has issues with the data to be provided.
Response: Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions. The SDT is aware of the extraneous influences in Net Actual Interchange values, and intends to select a sampling interval and an aggregation technique to minimize these influences. We apologize for the exclusion of Figure 1. The SDT has removed this figure from the revised instructions and has modified the FRS Form 1 and including instructions within the form to provide clarity in using the spreadsheet.		
SPP Standards Development	No	This document provides valuable background information regarding frequency deviations but lacks the specific line-by-line Form 1 instructions as mentioned at the top of page 7. We need those details, what goes in each column, how do we determine which values to use, etc. This would tend to minimize any confusion that currently exists regarding completing the form.One specific item we'd like to see provided in the instructions, as well as changed in Form 1, is carrying the Frequency Bias Setting value (Cell L32) out to two decimals. The current limitation of one decimal has caused confusion in past surveys.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		

Organization	Yes or No	Question 14 Comment
IRC Standards Review Committee	No	The document explains much of the FRS Form 1, but not all, as commented previously.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
ERCOT	No	The document explains much of the FRS Form 1, but not all, as commented previously.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
Progress Energy	No	The forms clarity can only truly be found by reverse engineering the formulas within each of the cells.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
ENBALA Power Networks	No	The FRS Form 1 Instructions that was downloaded from the supporting website seemed to be missing information on page 5. We found that the accompanying FRS Form 1 (excel document) was more useful than the actual instruction document in providing detail on the required calculation for the Bias Setting.
Response: The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
Energy Mark, Inc.	No	Comment 39: The following comments apply to Balancing Authority FRS Form 1 Background and Instructions.Section A: Comment 40: The last sentence in the second paragraph should be modified to read, “Therefore, it is better to analyze response only when significant frequency deviations occur until better measurement methods can be developed to overcome these difficulties.”Section A, Subsection 1, Frequency Response: Comment 41: The words “continuous and inverse relationship” should be changed to “bidirectional, continuous and inverse relationship” in all three bullets. Frequency Response that is not provided bi-directionally will be rapidly depleted by oscillating frequency events. Comment 42: If a BA has “non-bidirectional step-function Frequency Response” to frequency, it must also have sufficient continuous frequency response to restore frequency, frequency response, and frequency responsive reserves (margins) following the use of the “non-bidirectional step-function Frequency Response.” Therefore, the Frequency Response of primary interest for this standard is a subset of the Frequency Response defined in the NERC Glossary. Comment 43: Simulations and actual experience on the interconnections have demonstrated that step function Frequency Responses can result in frequency instability and oscillations when they are not effectively coordinated with bidirectional, continuous and inverse Frequency Response. Therefore, it is imperative that the standard differentiate this bidirectional, continuous and inverse Base Frequency Response from other

Organization	Yes or No	Question 14 Comment
		Supplemental Frequency Responses that can be applied under restricted conditions to supplement it.Section A, Subsection 2, Response to Internal and External Generation/Load Imbalances: Comment 44: Most AGC Systems use the Frequency Bias Setting in conjunction with the frequency deviation to determine whether an imbalance in load and generation is internal or external to the BA. This can only be done effectively when the Frequency Bias Setting matches the internal Frequency Response of the BA. Unless the minimum Frequency Bias Setting requirements are modified to allow this matching to be implemented, the most AGC Systems will be unable to perform as indicated in this subsection.Section A, Subsection 4, Effects of a Disturbance on all Balancing Authorities...: Comment 45: The description should be modified as follows; "When a loss of generation occurs, Interconnection frequency declines because machine speed must decrease to supply the energy shortfall from rotating kinetic energy. Initially, rotating kinetic energy from all rotating machines with direct mechanical-to-electrical coupling addresses the entire shortfall by lowering machine speed, and hence frequency, of the Interconnection*.* Initially, an amount of kinetic energy equal to the power (generation) lost will be withdrawn from the stored energy in rotating machines with direct mechanical-to-electrical coupling throughout the Interconnection. As the mechanical speeds are reduced, Interconnection frequency decreases proportionally. Comment 46: The term Inadvertent Interchange is not correctly used at the end of the first paragraph. Tie flow error indicates power. Inadvertent Interchange indicates energy (power integrated over an hour). A better sentence would be, "The resulting tie flow error (NIA - NIS) will be integrated into Inadvertent Interchange." Comment 47: The first sentence in the fifth paragraph states, "If the Frequency Bias Setting is greater (as an absolute value) than the Balancing Authority's actual Frequency Response, then its AGC will ... , which further helps arrest the frequency decline, but increases Inadvertent Interchange. Frequency decline is arrested within the first 10 seconds of an imbalance by the Frequency Response of the interconnection. AGC action is not initiated until many seconds after the frequency decline is arrested. Therefore, a Frequency Bias Setting greater than the actual Frequency Response will not result in the AGC System having any effect on the arrested frequency or make any contribution to arrest the frequency decline. The only effect will be to provide aid during the initial stages of the frequency recovery which is immediately withdrawn during the later stages of the frequency recovery, while contributing to Inadvertent Interchange. In fact, the effect of a Frequency Bias Setting greater than the actual Frequency Response is very similar to the effect the a BA receives from a reserve sharing group with the exception that the reserve sharing group does not withdraw the aid until after the frequency recovery has been completed. The last sentence in this paragraph is also incorrect for the same reasons stated previously. If a BA's Frequency Bias Setting is less than the actual Frequency Response, the BA will still contribute to arresting the frequency, however, it may withdraw its Frequency Response before the contingent BA or Reserve Sharing Group is able to initiate recovery contributing to further frequency decline or a delayed frequency recovery.Section A, Subsection 5, Effects of a Disturbance on the Contingent Balancing Authority: Comment 48: In the first sentence, the phrase "as allowed by the Frequency Bias Settings" refers to the

Organization	Yes or No	Question 14 Comment
		replacement power provided to the Contingent BA from the interconnection. The initial amount of replacement power supplied to the Contingent BA is unaffected by the Frequency Bias Settings. The Frequency Bias Settings will only affect how quickly the replacement power is withdrawn after the frequency is arrested and stabilizes. The risk is that the replacement power will be withdrawn before the Contingent BA or RSG can replace it. Comment 49: The two boxes indicating that the Point A and Point B values are averages should also indicate that the averaging periods for these calculations vary with the scan rate used to collect the data. The correct averaging periods were presented in Definitions of Frequency Values for Frequency Response Calculation in NERC Reference Document - Understand and Calculating Frequency Response.
Response: Comments 39 through 48: The SDT has removed the FRS Form 1 Background Document from this standard and therefore your comments concerning language within this document are not incorporated in this version. Comment 49: The SDT created FRS Form 2 to address your comments. In addition, the SDT has extensively modified the instructions for the use of these forms to provide additional clarity.		
EKPC	No	The form should include clear instructions for use and clear definitions for terms. All figures within the document should be viewable. More examples for various situations (non-conforming loads) should be included.
Response: The SDT has removed the FRS Form 1 Background Document from this standard and therefore your comments concerning figures within this document are not incorporated in this version. The SDT has modified the FRS Form 1 and included detailed instructions within the form to provide clarity in using the form.		
American Electric Power	No	The FRO value and calculation formula assigned by the ERO is not totally clear. The survey form should indicate the complete formula used by the ERO. It appears to be missing.
Response: The information you are referencing is now included in Attachment A. The SDT has also modified the FRS Form 1 and included detailed instructions to provide clarity in using the form.		
Duke Energy	No	The form does not recognize the impacts noted in the comment to 1 above. The form does show a column that appears to allow for exclusion of contingent BA events, but it is not clear how that is accomplished, nor how doing so matches the definitions currently proposed. Duke Energy agrees with the SERC OC comments “We believe the FRS form 1 instructions should be improved by better defining the terms used and improving the overall layout of the form. The document provided should be corrected so that all figures are viewable.” The form does not provide much in the way of instructions.

Organization	Yes or No	Question 14 Comment
Response: The SDT has removed the FRS Form 1 Background Document from this standard and therefore your comments concerning figures within this document are not incorporated in this version. The SDT has also modified the FRS Form 1 and included detailed instructions within the form to provide clarity in using the form.		
Santee Cooper	Yes	The instructions should include how to take into account changes in metered non-conforming loads.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified FRS Form 1 to allow for adjustments such as non-conforming load. The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
NIPSCO	Yes	We didn't read it but the form looks good.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has modified the FRS Form 1 and included instructions to provide clarity in using the form.		
Patterson Consulting, Inc.	Yes	There are inaccuracies that should be corrected, but the document is useful and valuable. The desired "averaging" of scan-cycle data included in FRS Form 1 Background and Instructions should be made mandatory to achieve the standard's purpose of providing consistent measurement methods.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT created FRS Form 2 to address the averaging issue identified in your comment. In addition, the SDT has extensively modified the instructions for the use of these forms to provide additional clarity. The SDT has also modified the FRS Form 1, correcting errors in the calculations.		
FMPP	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
NorthWestern Energy	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 14 Comment
Kansas City Power & Light	Yes	
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		

15. ***The SDT is soliciting comments on methods of obtaining Frequency Response to meet the FERC Order 693 directive. If possible please provide any thoughts you may have on this subject.***

Summary Consideration: Stakeholders provided the suggestions shown below as possible methods of obtaining Frequency Response to meet the FERC Order 693 directive:

1. Develop requirements applicable to the Generator Owner.
2. Address droop, dead band settings and governor operation.
3. Corroborate with manufacturers to address load demand response.
4. Use generator output as a primary input for calculating Frequency Response
5. Define ways Reserve Sharing Groups can assist Balancing Authorities in providing Frequency Response.
6. Write standard requirements based on performance needs.
7. Establish demand response as an ancillary service providing frequency response.
8. Do not apply the standard to entities that do not have generation resources.
9. Create a primary frequency market.
10. Keep the 1% method currently in use.
11. Ensure generators provide appropriate governor response and merchant generation contracts include a Frequency Response obligation.
12. Develop a specific continent wide Frequency Response definition.
13. Provide a customer compensated pre-emptive load shedding program.

In response to industry comments the SDT delivered to NERC staff the recommendation for collaboration between the ERO and manufacturers regarding load demand response. The SDT has specified in the latest draft standard other methods for a BA to obtain Frequency Response. The SDT will examine, during the field trial, the possibility of transferring Frequency Response between BAs.

Organization	Yes or No	Question 15 Comment
Santee Cooper		The SDT should consider focusing and directing requirements at root causes. Specifically, the SDT should develop requirements that apply to GOs and address droop requirements, deadband settings, governor operation, etc., as well as specific response expectations which are measured and compared to reported

Organization	Yes or No	Question 15 Comment
		settings. Such requirements would likely include exemption criteria to address older existing systems as well as current operating conditions. Newer systems should be developed, however, to meet specific requirements that will ultimately improve or maintain Frequency Response at acceptable levels. Subsequent efforts by the ERO should also consider collaboration with manufacturers to address demand responses associated with loads.
Response: This issue has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The SDT will pass on your suggestion concerning further collaborations between the ERO and manufacturers.		
Bonneville Power Administration		Primarily, frequency response comes from governor control at generators. In order to accurately measure this, the output of generation should be used as one of the primary inputs to the calculation of frequency response. Due to losses, as earlier explained, some BAs could be penalized due to losses associated with other BA frequency response flowing over the BAs' transmission system. This needs to be taken into account when calculating the frequency response of the BAs.
Response: The SDT does not have adequate information to address this suggestion. An impact study would be the best option for conducting an analysis.		
SPP Standards Development		The SDT has already offered a suggestion that Reserve Sharing Groups could assist Balancing Authorities in the provision of Frequency Response. We're not familiar with such arrangements within Reserve Sharing Groups and would need more information regarding the specifics of such sharing arrangements. That being the case, as written the draft standard does not provide for the provision of Frequency Response by any entity other than a Balancing Authority. Such arrangements would definitely have to be reflected in modifications to Form 1.
Response: Since these are new Requirements, existing RSG agreements most likely do not address Frequency Response. The SDT has revised the standard to include RSGs. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. The SDT will examine, during the field trial, the possibility of transferring Frequency Response between BAs.		
IRC Standards Review Committee		Demand Response performing as an ancillary service in which the resources are paid to reduce load upon automatic or manual deployment can provide frequency response. Other devices are available, such as flywheels or storage arrangements, such as battery banks, that can provide fast and sustainable response, could also provide frequency response. The standard must be written around performance requirements and results rather than prescriptive requirements that may have the unintended consequence of stifling innovation and creativity in this area. Within the ERCOT Interconnection and the ERCOT market construct, an ancillary service titled Load acting as a Resource (LaaR) may provide up to 50% of the responsive reserve requirement and provides automatic underfrequency relay activated response to frequency drops. Other market constructs provide for similar

Organization	Yes or No	Question 15 Comment
		services. As indicated in our comments under Q2, there is a missing piece to maintaining system frequency and arresting frequency deviation, and that is the generators' governor response. We suggest the SDT conduct an industry discussion on this subject, and determine the entity(ies) responsible for governor actions/setting, the mechanism to provide such a response, and the place for stipulating the necessary standard requirements to enforce compliance for governor actions before further developing this BAL-003-1 standard.
Response: Manual deployment is not quick enough for frequency response. Automatic deployment of other devices could be useful to provide the desired frequency response. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. Regarding governor response - this issue has been discussed and the SDT understands your concern However, generator droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns.		
ERCOT		Demand Response performing as an ancillary service in which the resources are paid to reduce load upon automatic or manual deployment can provide frequency response. Other devices are available, such as flywheels or storage arrangements, such as battery banks, that can provide fast and sustainable response, could also provide frequency response. The standard must be written around performance requirements and results rather than prescriptive requirements that may have the unintended consequence of stifling innovation and creativity in this area. Within the ERCOT Interconnection and the ERCOT market construct, an ancillary service titled Load acting as a Resource (LaaR) may provide up to 50% of the responsive reserve requirement and provides automatic underfrequency relay activated response to frequency drops. Other market constructs provide for similar services. As indicated in our comments under Q2, there is a missing piece to maintaining system frequency and arresting frequency deviation, and that is the generators' governor response. We suggest the SDT conduct an industry discussion on this subject, and determine the entity(ies) responsible for governor actions/setting, the mechanism to provide such a response, and the place for stipulating the necessary standard requirements to enforce compliance for governor actions before further developing this BAL-003-1 standard.
Response: Manual deployment is not quick enough for frequency response. Automatic deployment of other devices could be useful to provide the desired frequency response. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. Regarding governor response - this issue has been discussed and the SDT understands your concern However, generator droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns.		

Organization	Yes or No	Question 15 Comment
Kansas City Power & Light		The determination of sufficient frequency response in the interconnection is complex and varies according to the ratio of generation online and the load in the interconnection. The calculation of actual frequency response is also extremely challenging considering metering accuracy & resolution, SCADA sample rates, statistical variations of load and generation. To accurately assess what is needed and the methods to implement such a complex subject will take considerable thoughtfulness, time, testing and engineering ingenuity.
Response: The SDT agrees with your comments and thanks you for your participation.		
Progress Energy		We feel this problem exists on the generator level and this standard should only be applied to those entities and their response. This will impact BAs of vertically integrated companies. Entities without generation resources should not be held accountable for frequency response. If their energy supplier wants to make them responsible for purchasing ancillary response service, that will be up to them on how they distribute it. Based on the fact that schedules respond too slowly to meet the response window of the frequency measure, schedules should never be used to measure response capabilities, thus making ancillary service unnecessary.
Response: The SDT agrees that schedules are too slow to be used for Frequency Response. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. The SDT is responding to a FERC directive to "...define methods of obtaining Frequency Response..." Regarding governor response - this issue has been discussed and the SDT understands your concern However, generator droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. Also, Requirements imposed on generators is outside the scope of the project approved SAR.		
ENBALA Power Networks		ENBALA supports the creation of a Primary Frequency Market. This could be achieved in two methods: Implementation of a new Market for Primary Frequency Response Or Including in the definition of spinning reserves the requirement for resources to be capable of providing Primary Frequency Response through autonomous and local control by governor action and inertial response. And We particularly encourage the participation from all resources capable of providing this service in a coordinated approach, including alternative technologies such as controllable loads, energy storage, electrically-coupled wind farm controls, and demand response. Furthermore, we stress that this service needs to be a coordinated, autonomous, and local control and should NOT be integrated in the AGC system.

Organization	Yes or No	Question 15 Comment
Response: The NERC Reliability Standards do not necessarily dictate "how" Requirements are satisfied. A market can be created by a region, sub-region, ISO, RTO or other entities as appropriate to facilitate compliance however the NERC Reliability Standards do not establish markets.		
NIPSCO		We reviewed the related NERC Training Document from 2003 and your proposed method seems like the best approach.
Response: The SDT thanks you for your support.		
NorthWestern Energy		A Balancing Authority's frequency response is based upon a "median" value calculated from analyzing multiple events. Frequency response during some of these events is better than others, depending on the system conditions at the time and the amount system loading and unloaded generation online at the time of the event. Given these circumstances a BA's actual response could vary by event (better or worse than median), thus compliance measurement per event to a frequency response obligation based on the median response (over multiple events) could put BA's in non-compliant situations unjustly. Page 2 implies that there is currently too much frequency response based on the 1% of peak demand method of establishing frequency bias. Even though NWE does not use the 1% method, NWE feels that the 1% minimum has been a tried and true method of providing frequency response in the Western Interconnection. Without the 1% minimum (and BA's using a natural response less than the 1%), the total interconnection frequency response would decrease according to research. This would lead to decreased interconnection bias, causing other operational issues, such as lower L10 values and possible CPS2 compliance factors.
Response: The drafting team agrees that there is great variability in calculated frequency response event to event. This is because in a multi-BA Interconnection, a given BA's frequency response contribution is small compared to the variations in load and generation within the BA at any given moment. This is why the drafting team is proposing to use the median value of many events during the year as the measure of "average" response. The median is the preferred measure of by statisticians when dealing with data populations containing outliers. The SDT agrees the Interconnections possess sufficient frequency response. The drafting team is proposing a test allowing all BAs with frequency response less than the 1% of peak to use a Frequency Bias Setting set less than 1% of peak to better match the Frequency Bias setting to the natural response. The drafting team agrees a floor threshold needs to be maintained however the current 1% of peak requirement is causing many BAs to over-bias, causing undulations in ACE and frequency. The SDT would appreciate it if you could identify the research indicating control problems would be realized if the minimum bias setting was set less than 1%. The SDT also agrees CPS compliance scoring may be affected which is why the drafting team proposes testing using incremental changes to the Frequency Bias Setting. Research by Nathan Cohn (Control of Generation and Power Flow on Interconnected Systems) implies that better matching of the Frequency Bias Setting to the system Frequency Response Characteristic will improve AGC and frequency performance, and also improve CPS compliance scoring. The SDT does not agree that there is excessive frequency response because of the 1% of peak demand method for establishing the Frequency Bias Setting. The		

Organization	Yes or No	Question 15 Comment
bias setting does not increase or decrease Primary Frequency Control. The bias setting value will only impact the measure of ACE and resulting Secondary Control. The 1% of peak minimum threshold was appropriate in the past when BA Primary Frequency Control was nearly equal to 1% of the forecasted peak load or peak generation. Keep in mind FRS Form 1 and the BAL-003 draft standard still require the ACE Frequency Bias Setting be set equal to or greater than the Frequency Response Characteristic with an initial minimum value of 0.8% of the BA forecasted peak load or peak generation. When the BA Frequency Bias Setting better matches the Frequency Response Characteristic, L10 and CPS1 and CPS2 will more accurately measure the BA's ACE impact on Interconnection frequency. This may result in lower CPS1 and CPS2 compliance scoring than currently realized. The sample size of selected events used for analysis is intended to minimize the concern about variability of performance observed on an event-to-event basis so that the BA can realize a consistent reference measure when performing analysis.		
Energy Mark, Inc.		Comment 50: In those regions of North America where energy is supplied through markets, Frequency Response should be defined as an additional Ancillary Service and acquired through these Ancillary Service Markets. Attempts to acquire Frequency Response through methods external to the Ancillary Service markets will contribute to market inefficiencies since these external methods must affect the capacity available to the Ancillary Service markets. Use of out-of-market methods would oppose the very reasons that electric energy markets were created in the first place. Comment 51: BAs not participating in formal RTOs or ISOs could obtain Frequency Response by insuring that their owned generation is providing appropriate Governor Response to the BA and that contracts will merchant generation are modified to include the provision of Frequency Response in the merchant contracts. It may be appropriate to request guidance from regulatory agencies encouraging the renogiation efforts required to modify existing merchant generator contracts. Comment 52: Whether Frequency Response is obtained through Ancillary Service Markets, merchant generator contracts or owned generation, specific continent wide definitions for Frequency Response should be developed to provide guidance and consistency in these diverse circumstances. NERC should be taking the lead on developing the necessary continent wide definitions or policies for Frequency Response.
Response: Comments 50 & 51: The NERC Reliability Standards do not necessarily dictate "how" Requirements are satisfied. A market can be created by a region, sub-region, ISO, RTO or other entities as appropriate to facilitate compliance however the NERC Reliability Standards do not establish markets. Comment 52: The SDT will forward this comment to NERC staff.		
Beacon Power Corporation		Beacon Power is a manufacturer and merchant developer of an innovative advanced energy storage technology that uses flywheels. Beacon Power's technology operates by using flywheels to rapidly recycle energy from the grid in order to follow moment-by-moment changes in frequency nearly instantaneously. The following characteristics of Beacon's technology support the use of this technology for frequency response on the electric grid. â˘ Responds to local frequency change in less than 1 second; full response in less than 4 seconds â˘ State of the art electronic control - accurate response. No dead-band required, but could be incorporated if beneficial - Inherently modular - Can be distributed around the grid. With distributed local

Organization	Yes or No	Question 15 Comment
		response to frequency, less likely to be limited by congestion, and ensures islanded portions of the grid maintain frequency response. The ability of Beacon Power's flywheels to quickly and precisely respond to frequency events on the grid makes this technology an ideal source of frequency response. The fast response provided can aid in arresting rapid frequency decline on the system, which can assist in preventing the frequency nadir from encroaching on the first step of Under Frequency Load Shedding. Because of its modular design, flywheels can be built and positioned throughout the grid to provide a diversified frequency response, ensuring adequate response during events that cause the grid to separate into islands. Any standards developed by NERC must allow energy storage and should be inclusive of all technologies able to provide frequency response. Storage resources that provide frequency response should be allowed to recover their costs as a wholesale transmission facility subject to FERC's jurisdiction. Storage facilities do not generate electricity and operate only to enhance the reliability of transmission service. Given that there is no open-market for frequency response, there are no concerns of cross-subsidization or competitive concerns. This will address the FERC Order 693 directive to develop a method of obtaining frequency response, and will improve the overall reliability of the interconnections. Beacon agrees with the approach of mandating Balancing Authority response. However, the SDT should go further to define performance requirements for different tiers of frequency response, for example full response in 5 seconds maintained until 15 seconds, and full response in 15 seconds maintained until 90 seconds (numbers are for example only, the SDT would determine the appropriate values), so that Balancing Authorities can be confident when acquiring new sources that demonstrate those performance characteristics. The use of Reserve Sharing Groups (as detailed in Attachment A) to provide a means of sharing Frequency Response seems unnecessary. Since Frequency Response is contributed to the entire interconnection, ignoring any propagation delays, any Balancing Authorities within an interconnection can share Frequency Response if a consistent method of measuring and allocating it can be determined. However, since all online sources of Frequency Response will contribute based on the change in frequency, this sharing of Frequency Response will not improve interconnection performance. It will only allow Balancing Authorities with too few sources to meet NERC requirements. Hence, sharing arrangements would only improve frequency performance if it results in more frequency responsive sources being online during an event. Additionally, due to the geographical differences of the Balancing Authorities within the Reserve Sharing Groups, their use is not conducive to a diversified interconnection frequency response.
Response: Frequency Response required by the Standard fully satisfies the reliability needs of each Interconnection. Since these are new Requirements, existing RSG agreements most likely do not address Frequency Response. The SDT is just offering this as a suggestion that needs to be vetted. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response.		
Westar Energy		RSG and Spinning Reserve today is SECONDARY response. How does FERC see the RSG (or RTO markets) providing PRIMARY frequency response? Allowing the RSG option does not "address the 693

Organization	Yes or No	Question 15 Comment
		directive", only dumps it on the RSG with no direction. Using frequency responsive loads seems impractical based on the small frequency deviation levels required. What customer would be ok with dropping load when frequency drops to 59.964 or 59.92, etc.
Response: Since these are new Requirements, existing RSG agreements most likely do not address Frequency Response. The SDT is just offering this as a suggestion that needs to be vetted. The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. Customers are not required to provide frequency responsive load for reliability however this is an options entities may wish to explore.		
ISO New England Inc.		As indicated previously in our comments, there is missing piece to maintaining system frequency and arresting frequency deviation, and that is the generators' governor response. This standard appears to incorrectly assume that the BAs have the resources/ability to provide (primary) Frequency Response, and this is simply not the case. The BAs do not necessarily own facilities which can provide this service.
Response: The SDT is responding to a FERC directive to "...define methods of obtaining Frequency Response..." The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. Regarding governor response - this issue has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns.		
Independent Electricity System Operator		As indicated in our comments under Q2, there is missing piece to maintaining system frequency and arresting frequency deviation, and that is the generators' governor response. We suggest the SDT conduct an industry discussion on this piece, and determine the entity responsible for governor actions/setting, the mechanism to provide such a response, and the place for stipulating the necessary standard requirements to enforce compliance for governor actions before further developing this BAL-003-1 standard.
Response: The NERC Reliability Standards do not dictate how Requirements are satisfied. The SDT believes each Interconnection possesses sufficient frequency response. Regarding governor response - this issue has been discussed and the SDT understands your concern. However, governor droop requirements, dead-band settings and governor operation are outside the scope of the project approved SAR. The SDT believes that the Generator Verification standards will help address these concerns.		
Duke Energy		The efforts to develop the MOD-025/026 standards and the associated work to determine actual and predicted generator response will do much to identify the response available and provide ways to plan for and validate the response needed and supplied. ERCOT has demonstrated effective use of Load Acting as a Resource (LAAR - essentially customer compensated pre-emptive load shedding). Exploration of similar applications of this in other interconnections is warranted.

Organization	Yes or No	Question 15 Comment
Response: The NERC Reliability Standards do not necessarily dictate "how" Requirements are satisfied. A market can be created by a region, sub-region, ISO, RTO or other entities as appropriate to facilitate compliance however the NERC Reliability Standards do not establish markets.		
Patterson Consulting, Inc.		The SDT has taken the correct approach in mandating Balancing Authority response. Balancing Authorities should be able to acquire that response from various sources to create a suitable portfolio to meet the required performance. The industry may benefit if the SDT defined required performance characteristics for Frequency Response from a technical perspective, such as initial response in less than 2-8 seconds, maximum response in less than 2-40 seconds, continuous (or not) response, etc. (These values are examples and should be determined by the SDT.) Once the market and industry understand expectations, existing or new technologies with those characteristics become possible sources. Then, it is just a matter of adjusting tariffs (compensation) to incent implementation. If Frequency Response is allowed to be shared between Balancing Authorities, the SDT must create requirements to address such issues as deliverability, measurement, and suitable electrical diversity throughout the interconnection.
Response: The SDT agrees with your comment. However, keep in mind that the SDT is responding to a FERC directive to "...define methods of obtaining Frequency Response..." The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response. The SDT is evaluating several averaging time periods during the field trial. The SDT will select the averaging time period that provides the most accurate results.		
Alberta Electric System Operator		Frequency Response has different aspects and time frames (inertia, governor and AGC response), the method of obtaining Frequency Response should respect these different aspects and time frames.
Response: The SDT is responding to a FERC directive to "...define methods of obtaining Frequency Response..." The SDT has also specified in the latest draft standard version other methods for a BA to obtain Frequency Response.		
FirstEnergy		See our responses to Question 4.
Response: Please refer to our response to Question 4.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		

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

Summary Consideration: Most of the commenters responding to this question provided a response but did not identify any conflicts. A couple of the commenters felt that there may be a conflict with both the FERC Order 693 and the FERC March 18, 2010 order. Another commenter felt that the requirements could impact CPS performance and that using events from the prior evaluation period could create the possibility of double jeopardy.

The SDT explained that the comment concerning the "…scheduled periodicity of Frequency Response surveys…" being the only issue needing to be addressed at this time was not correct. The SDT stated that in the December 16, 2010 FERC Order Accepting NERC's Compliance Filing the Commission states in par 12 "…NERC's proposed action plan demonstrates a commitment to develop requirements for minimum levels of frequency response needed for Reliable Operation consistent with the Commission's directives in Order No. 693." The SDT believes that this clearly states that the directives from FERC Order 693 are to be addressed.

Concerning the comment that the requirements could impact CPS performance the SDT explained that it believes that the large gap commonly found between natural frequency response and the frequency bias settings deployed based on 1% of peak load was resulting in excessive and unnecessary regulation and was related to high frequency following DCS events and in other circumstances as well. The SDT agreed that the reduction of the 1% of peak load floor for the frequency bias setting can affect the total interconnection frequency bias setting, L10 values, and possibly CPS 2 compliance as well. The SDT further explained that it put Requirement R5 back in the proposed standard with a process for reducing the minimum to provide for monitoring the system to ensure reliable operation.

With regards to the comment concerning the possibility for double jeopardy the SDT responded that the SDT expected each year to normally have enough frequency events to avoid double jeopardy, but there was a need to have a backup plan in case a year does not yield sufficient frequency events.

Organization	Yes or No	Question 16 Comment
FirstEnergy		We are not aware of any conflicts at this time.
Response: The SDT thanks you for your participation.		
IRC Standards Review Committee		This proposed Field Trial and standard MAY conflict with Order 693 and the March 18, 2010 Order that state:Specifically, the Commission stated: As the Commission noted in the NOPR and in our response to FirstEnergy, Requirement R2 of this Reliability Standard states that "[e]ach Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response." The Commission believes that the achievement of this Requirement is fundamental to the tie line bias control schemes that have been in use to assist in balancing generation and load in the Interconnections for many years.

Organization	Yes or No	Question 16 Comment
		Further, in Order No. 693 the Commission concluded: We understand that the present Reliability Standard sets the required frequency response of the balancing authorities to be approximately one percent or greater by requiring that the frequency bias shall not be less than one percent and that the frequency bias be as close as practical to, or greater than, the actual frequency response. March 18 Order concludesAccordingly, to assure that NERC proceeds expeditiously, the Commission is setting a compliance deadline of six months from the date of issuance of this order for the development of modifications to Reliability Standard BAL-003-0 that comply with the Commission's directives as set forth in Order No. 693 to define the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met and the necessary amount of frequency response needed for reliable operation. May 13, 2010 Order for a Technical Conference statedThus, we direct that NERC submit, within 30 days after the technical conference, a proposed schedule that includes firm deadlines for completing studies, analyses needed to develop a frequency response requirement, and for submission of a modified Reliability Standard that is responsive to the Commission directives in Order No. 693 pertaining to Reliability Standard BAL-003-0. In short the Orders only ask for the BAL-003 to be revised to provide a schedule for the Frequency Response surveys. We may question whether the subjective 25 events per year is the same as a scheduled periodicity, but the point here is that that is the only mandate that is needed immediately. The only other requirement is that NERC file a schedule for completing its studies. Note that is not something that is for a standard it is something for a NERC filing.
Response: The SDT disagrees with your comment concerning the "...scheduled periodicity of Frequency Response surveys..." being the only issue needing to be addressed at this time. In the December 16, 2010 FERC Order Accepting NERC's Compliance Filing the Commission states in par 12 "...NERC's proposed action plan demonstrates a commitment to develop requirements for minimum levels of frequency response needed for Reliable Operation consistent with the Commission's directives in Order No. 693." This clearly states that the directives from FERC Order 693 are to be addressed.		
ERCOT		This proposed Field Trial and standard MAY conflict with Order 693 and the March 18, 2010 Order that state:Specifically, the Commission stated: As the Commission noted in the NOPR and in our response to FirstEnergy, Requirement R2 of this Reliability Standard states that "[e]ach Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response." The Commission believes that the achievement of this Requirement is fundamental to the tie line bias control schemes that have been in use to assist in balancing generation and load in the Interconnections for many years. Further, in Order No. 693 the Commission concluded: We understand that the present Reliability Standard sets the required frequency response of the balancing authorities to be approximately one percent or greater by requiring that the frequency bias shall not be less than one percent and that the frequency bias be as close as practical to, or greater than, the actual frequency response. March 18 Order concludesAccordingly, to assure that NERC proceeds expeditiously, the Commission is setting a compliance deadline of six months from the date of issuance of this order for the development of modifications to Reliability Standard BAL-003-0 that comply with the Commission's directives

Organization	Yes or No	Question 16 Comment
		as set forth in Order No. 693 to define the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met and the necessary amount of frequency response needed for reliable operation. May 13, 2010 Order for a Technical Conference statedThus, we direct that NERC submit, within 30 days after the technical conference, a proposed schedule that includes firm deadlines for completing studies, analyses needed to develop a frequency response requirement, and for submission of a modified Reliability Standard that is responsive to the Commission directives in Order No. 693 pertaining to Reliability Standard BAL-003-0. In short the Orders only ask for the BAL-003 to be revised to provide a schedule for the Frequency Response surveys. We may question whether the subjective 25 events per year is the same as a scheduled periodicity, but the point here is that that is the only mandate that is needed immediately. The only other requirement is that NERC file a schedule for completing its studies. Note that is not something that is for a standard it is something for a NERC filing.
Response: The SDT disagrees with your comment concerning the "...scheduled periodicity of Frequency Response surveys..." being the only issue needing to be addressed at this time. In the December 16, 2010 FERC Order Accepting NERC's Compliance Filing the Commission states in par 12 "...NERC's proposed action plan demonstrates a commitment to develop requirements for minimum levels of frequency response needed for Reliable Operation consistent with the Commission's directives in Order No. 693." This clearly states that the directives from FERC Order 693 are to be addressed.		
Arizona Public Service Company		AZPS would like clarity if Interpretations of BAL-003-0 will be part of BAL-003-1.
Response: This standard will replace all existing BA-003's and incorporates any approved interpretation.		
Energy Mark, Inc.		Comment 53: In Comment 25 I indicated that the suggested allocation method fails to meet the requirement that "A reliability standard shall neither mandate nor prohibit any specific market structure." My comments here support that contention. The allocation method is not influenced by demand for frequency response. As a consequence, only one side of a fair market is represented. Markets are effective because: 1. Markets are voluntary allowing the demand side of the market to choose to not create the need to acquire a product or service. 2. Markets select the lowest cost product or service from competing offers to supply the product or service demanded.When the allocation method is blind to the demand for the product or service it eliminates the most efficient market designs from consideration, and therefore, mandates a market design that only looks at the supply side of the market. Comment 54: Selecting an allocation method for Frequency Response that considers both the supply and demand sides of the market for Frequency Response would enable the implementation of a much more efficient market design. Such an allocation method would allow demand side reductions in the need for Frequency Response to compete with supply side increases in the need for Frequency Response allowing for

Organization	Yes or No	Question 16 Comment
		the creation of the most efficient markets in this Ancillary Service.
Response: The SDT acknowledges your concerns but your market-related suggestions are outside the scope of the industry approved SAR.		
FMPP		NERC Relablity Standards Conflict - by using events from last year to determine an entity's compliance with a Requirement for this year puts the entity in double jeopardy for last year's events, which were already used for compliance for last year.
Response: The SDT agrees that a standard should not place an entity in double jeopardy. The SDT expects that each year will normally have enough frequency events to avoid double jeopardy, but it needs to have a backup plan in case a year does not yield sufficient frequency events.		
American Electric Power		This Standard has the potential to affect Standards involving CPS performance with respect to the calculated CPS Bounds L10 if relative.
Response: The SDT believes that the large gap commonly found between natural frequency response and the frequency bias settings deployed based on 1% of peak load is resulting in excessive and unnecessary regulation and is related to high frequency following DCS events and in other circumstances as well. You are correct in asserting that the reduction of the 1% of peak load floor for the frequency bias setting can affect the total interconnection frequency bias setting, L10 values, and possibly CPS 2 compliance as well. The SDT has put Requirement R5 back in the proposed standard. The SDT has modified the plan for reduction of the minimum Frequency Bias Setting. The plan is no longer tied to the Field Trial. The SDT has removed the table reflecting the reduction of the minimum bias setting. The SDT is proposing a method of reducing the minimum Frequency Bias Setting in which the ERO will monitor the results of the reductions and adjusting them accordingly in an effort to bring the Frequency Bias Setting closer to natural Frequency Response. Please refer to Attachment B for details of this reduction plan.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		
Patterson Consulting, Inc.		None.
Kansas City Power & Light		No other comments.

17. ***Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1.***

Summary Consideration: Several commenters indicated that the supplemental compliance information and attachment sections created additional standard requirements. In response to this concern these documents have been revised. If a requirement states that the entity must perform in accordnace with Attachment X, then Attachment X is an extension of that requirement and the performance identified in the attachment is mandatory and enforceable.

Several commenters expressed concern that the Balancing Authority may not have the necessary means to effectively manage Frequency Response and recommended that the SDT consider establishing a standard for generators to support the Balancing Authorities achieve the necessary level of Frequency Response. The SDT explained that this standard will provide the metrics for Frequency Response while the market will define itself.

Commenters also stated that insufficient detail has been provided for evaluating the appropriateness of the methodology used for determining FRO. They indicated that the standard needed more details on how the FRO is calculated and allocated among the Balancing Authorities. The SDT made significant modifications to Attachment A – Supporting Document which details the methodology used to determine the calculations.

Commenters indicated that the plan to annually reduce the floor percentage for the Frequency Bias Settings may adversely impact reliability. In response to this concern the Implementation Plan no longer outlines the Frequency Bias Setting reduction plan initially proposed. Attachment B sets forth the procedure for reducing the Frequency Bias Setting floor threshold.

Another commenter stated that emphasis should be placed on the Frequency Excursion Curve Point C value and not other values because the Point C value is critical for reliability. A request was also received to correlate the frequency response for the Point B value timeframe window with the timeframe window for the Point C value. The SDT committed to reviewing this relationship during the field trial.

One commenter asked how to attain or schedule Frequency Response from another Balancing Authority if it is a market resource. The SDT responded that the standard simply provides reliability metrics. Industry determines which markets and independent solutions could be developed.

A comment was received requesting clarification of the NERC glossary term “native load” mentioned in the Implementation Plan. Instead of providing clarification, this term has been removed from the Implementation Plan.

Twenty-five additional industry comments have been received regarding the draft BAL-003-1 standard as noted in the following table.

Organization	Question 17 Comment
Northeast Power Coordinating Council	It is not clear from either Form 1 or its instructions whether the supplied frequency deviation for an event should be used without modification, or if it should be overwritten with a value computed from the Balancing Authority’s data source (or if

Organization	Question 17 Comment
	there is an option, to use the lesser value, for example). Clearly express which frequency deviation value to use. The load sensitivity calculation is an important Balancing Authority Area value to compute accurately for modeling purposes. As proposed, it would use the same computational technique as that used for frequency bias sampling calculations. To yield a useful result, load values would need to have “convergence characteristics” similar to that found in the actual net interchange values used for frequency bias sampling. While experience has shown that the average or median values of the frequency bias samples computed for most Balancing Authorities will converge with about 20 samples, a similar outcome for load sensitivity calculations might not occur. Frequency bias samples rely on the measured actual net interchange values that are sampled at the AGC scan rate, and the actual net interchange tends to be a rather stable value because AGC and operator actions usually keep the actual net interchange close to a scheduled value. The total net system load may have greater volatility and may be trending in a particular direction much more often than actual net interchange. Also, the load calculation typically relies on adding the sum of the generation within the Balancing Authority to the actual net interchange. The generation values may have a slower scan rate, longer data latency periods, and smaller generators might not be telemetered, with hourly scheduled values or manually entered values being used instead. These differences can contribute to a very different convergence characteristic than that found for actual net interchange. Simply put, the load sensitivity calculation needs validation. The Form 1 instructions mention a generation only Balancing Authority form to be filled in. It is not shown on the spreadsheet provided, and it is not clear what data should be entered, though it seems like it would still be actual net interchange.Form 1 contains an entry form for a single Balancing Authority Interconnection, however, it is not referenced in the Form 1 instructions.Section A of the Form 1 instructions contains excellent background material that explains why this effort is important. However, section B needs a careful review so that the instructions are thorough and unambiguous.The information on variable bias calculations seems sparse, and the requirements for variable bias should be reviewed thoroughly with those Balancing Authorities that are familiar with the nuances and challenges of determining an appropriate variable bias.If BIAS is set equal to response, about 50% of the time, AGC will cancel out the primary response; the BIAS, therefore, should be slightly higher than the natural response but clearly 1% is too large. The game plan to continually reduce the floor percentage for frequency bias settings needs to be reconsidered. With .4% peak load being a typical actual frequency response lately for Balancing Authorities, the 1% of peak load to .8% of peak load transition seems prudent. Perhaps a further reduction to .6% may be useful as well, but lesser floors may in effect result in AGC too often canceling out the primary frequency response being provided.While the 16 to 52 second sampling window for point B computations seem to be a reasonable initial guess for the metric, preliminary studies by the Frequency Responsive Reserve Standard Drafting Team (FRRSDT) indicate that AGC contributions from fast acting hydro generators will be included in the samples. As those same studies were not conclusive, perhaps the initial years of this standard could require the provision of scan rate data from 30 seconds before to 60 seconds after the start of the frequency decline for each event. While this significantly increases the volume of data to be provided, it would allow the FRRSDT to determine the best sampling intervals to be used. Perhaps a point B sampling interval of 15 to 30 seconds would filter out most of the fast acting AGC, but more data/analysis is needed to determine the best sampling interval to be sure that the primary response data is not being corrupted by this fast acting AGC response.To support Balancing Authorities in achieving the targeted level of frequency response, a standard for generators is needed as well, as they are historically the largest source of discretionary frequency response. The standard could give a Balancing Authority the right to waive these requirements should they pursue other sources of frequency

Organization	Question 17 Comment
	response, such as ERCOT's "load acting as a resource (LAAR)" efforts. Point C values are the more important reliability metric. Since point C metrics are challenged with data quality issues on a Balancing Authority and generator level, an effort should be made to correlate the required frequency response in the point B time window with that needed in the point C time window (perhaps using rules of thumb, such as 100% of load's frequency response and 30% of generator's frequency response occurs in time for point C). While Attachment A mentions that N-2 category C events will be used to determine the frequency response obligation on an interconnection level, there is insufficient detail provided at this time to evaluate the appropriateness of the obligations selected. Efforts in this area for the frequency model developed by the Reliability-Based Control Standard Drafting Team (and now the BARCSDT) for HQTE may shed some insight into this process.
Response: The SDT agrees that clearer instructions are needed in Form 1. This has been addressed in the revised form. The SDT also agrees that there may be limited benefit from measuring the load response of a BA due to data fidelity and resolution. An attempt to measure a BA's load response was included for the field trial to determine its value and was not used in the BA's frequency response measure. It is believed that some BA's with generation data that is on a similar scan rate as their Interchange data may find that it accurately measures their load dampening. The field trial will determine if it is useful or not. The SDT agrees that the 16 to 52 second sampling window may include some fast acting AGC. The field trial will determine if this sampling period should be reduced. Form 1 has been revised to include a minimum data set that starts 30 seconds before the event and ends not earlier than 60 seconds after the event to help identify the overall best averaging periods. The SDT also agrees that the use of LaaRs in ERCOT is a great backup to Primary Frequency Control but would also like to point out that this response only responds in one direction and does not provide bidirectional frequency stability for the moment to moment changes in frequency. Once utilized, it takes hours to restore the service for the next contingency. During this time, the BA and Interconnection depends on Primary Frequency Control from other sources that are continuous and bidirectional as long as headroom is available. The SDT agrees that Point C Primary Frequency Control is critical for preventing UFLS and will use the field trial results to determine if the Point B measure of performance can be correlated to Point C performance. Thank you for your comments. Regarding governor response - this issue concerning generators has been discussed by the SDT. The SDT understands your concern. However, governor droop requirements, dead-band settings, and governor operation is outside of the industry approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The N-2 criteria is being evaluated during the field trial.	
ISO New Engand Inc.	It is not clear from either Form 1 or its instructions whether the supplied frequency deviation for an event should be used without modification, or if it should be overwritten with a value computed from the Balancing Authority's data source (or if there is an option, to use the lesser value, for example). Clearly express which frequency deviation value to use. 2. The load sensitivity calculation is an important Balancing Authority Area value to compute accurately for modeling purposes. As proposed, it would use the same computational technique as that used for frequency bias sampling calculations. To yield a useful result, load values would need to have "convergence characteristics" similar to that found in the actual net interchange values used for frequency bias sampling. While experience has shown that the average or median values of the frequency bias samples computed for most Balancing Authorities will converge with about 20 samples, a similar outcome for load sensitivity calculations might not occur. Frequency bias samples rely on the measured actual net

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	interchange values that are sampled at the AGC scan rate, and the actual net interchange tends to be a rather stable value because AGC and operator actions usually keep the actual net interchange close to a scheduled value. The total net system load may have greater volatility and may be trending in a particular direction much more often than actual net interchange. Also, the load calculation typically relies on adding the sum of the generation within the Balancing Authority to the actual net interchange. The generation values may have a slower scan rate, longer data latency periods, and smaller generators might not be telemetered, with hourly scheduled values or manually entered values being used instead. These differences can contribute to a very different convergence characteristic than that found for actual net interchange. Simply put, the load sensitivity calculation needs validation.The Form 1 instructions mention a generation only Balancing Authority form to be filled in. It is not shown on the spreadsheet provided, and it is not clear what data should be entered, though it seems like it would still be actual net interchange.Form 1 contains an entry form for a single Balancing Authority Interconnection, however, it is not referenced in the Form 1 instructions.Section A of the Form 1 instructions contains excellent background material that explains why this effort is important. However, section B needs a careful review so that the instructions are thorough and unambiguous.The information on variable bias calculations seems sparse, and the requirements for variable bias should be reviewed thoroughly with those Balancing Authorities that are familiar with the nuances and challenges of determining an appropriate variable bias.If BIAS is set equal to response, about 50% of the time, AGC will cancel out the primary response; the BIAS, therefore, should be slightly higher than the natural response but clearly 1% is too large. The game plan to continually reduce the floor percentage for frequency bias settings needs to be reconsidered. With .4% peak load being a typical actual frequency response lately for Balancing Authorities, the 1% of peak load to .8% of peak load transition seems prudent. Perhaps a further reduction to .6% may be useful as well, but lesser floors may in effect result in AGC too often canceling out the primary frequency response being provided. While the 16 to 52 second sampling window for point B computations seem to be a reasonable initial guess for the metric, preliminary studies by the Frequency Responsive Reserve Standard Drafting Team (FRRSDT) indicate that AGC contributions from fast acting hydro generators will be included in the samples. As those same studies were not conclusive, perhaps the initial years of this standard could require the provision of scan rate data from 30 seconds before to 60 seconds after the start of the frequency decline for each event. While this significantly increases the volume of data to be provided, it would allow the FRRSDT to determine the best sampling intervals to be used. Perhaps a point B sampling interval of 15 to 30 seconds would filter out most of the fast acting AGC, but more data/analysis is needed to determine the best sampling interval to be sure that the primary response data is not being corrupted by this fast acting AGC response. To support Balancing Authorities in achieving the targeted level of frequency response, a standard for generators is needed as well, as they are historically the largest source of discretionary frequency response. The standard could give a Balancing Authority the right to waive these requirements should they pursue other sources of frequency response, such as ERCOT’s “load acting as a resource (LAAR)” efforts. Point C values are the more important reliability metric. Since point C metrics are challenged with data quality issues on a Balancing Authority and generator level, an effort should be made to correlate the required frequency response in the point B time window with that needed in the point C time window (perhaps using rules of thumb, such as 100% of load’s frequency response and 30% of generator’s frequency response occurs in time for point C).While Attachment A mentions that n-2 category C events will be used to determine the frequency response obligation on an interconnection level, there is insufficient detail provided at this time to evaluate the appropriateness of the obligations selected. Efforts in this area for the

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	frequency model developed by the Reliability-Based Control Standard Drafting Team (and now the BARCSDT) for HQTE may shed some insight into this process.
Response: The SDT agrees that clearer instructions are needed in Form 1. This has been addressed in the revised form. The SDT also agrees that there may be limited benefit from measuring the load response of a BA due to data fidelity and resolution. An attempt to measure a BA's load response was included for the field trial to determine its value and was not used in the BA's frequency response measure. It is believed that some BA's with generation data that is on a similar scan rate as their Interchange data may find that it accurately measures their load dampening. The field trial will determine if it is useful or not. The SDT agrees that the 16 to 52 second sampling window may include some fast acting AGC. The field trial will determine if this sampling period should be reduced. Form 1 has been revised to include a minimum data set that starts 30 seconds before the event and ends not earlier than 60 seconds after the event to help identify the overall best averaging periods. The SDT also agrees that the use of LaaRs in ERCOT is a great backup to Primary Frequency Control but would also like to point out that this response only responds in one direction and does not provide bidirectional frequency stability for the moment to moment changes in frequency. Once utilized, it takes hours to restore the service for the next contingency. During this time, the BA and Interconnection depends on Primary Frequency Control from other sources that are continuous and bidirectional as long as headroom is available. The SDT agrees that Point C Primary Frequency Control is critical for preventing UFLS and will use the field trial results to determine if the Point B measure of performance can be correlated to Point C performance. Thank you for your comments. This issue concerning generators has been discussed by the SDT. The SDT understands your concern. However, governor droop requirements, dead-band settings, and governor operation is outside of the industry approved SAR. The SDT believes that the Generator Verification standards will help address these concerns. The N-2 criteria is being evaluated during the field trial.	
Santee Cooper	Again, we believe that the SDT should consided or prior years' data. We are concerned with how the total frequency response obligation of an interconnection will be determined since this will ultimately determine each BA's FRO. We believe more detail should be presented on this issue.We appreciate the time and the work performed by the standard drafting team on this standard that we feel is a necessary component for reliable operation of the Interconnections.
Response: The SDT does not understand the intent of the first sentence in your comment.. The next posting will be more explicit in the method for determining the FRO.	
MRO's NERC Standards Review Subcommittee	We feel the Reserve Sharing Group should be removed from the applicability section as it's not included in any requirement.
Response: The SDT has modified the proposed standard to better reflect the RSG responsibility in providing Frequency Response.	
Xcel Energy	We feel Reserve Sharing Group should be removed from the applicability section since it is not included in any of the requirements. Additionally, the documents are not clear as to how there is a field trial included in the proposal.

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Response: The SDT has modified the proposed standard to better reflect the RSG responsibility in providing Frequency Response.	
LG&E and KU Energy	We are concerned that, in attachment A, the generation/load split in determining FRO may not be the most equitable method for allocation. In general, we feel that Attachment A needs additional clarity, i.e., is the split based on forecasted or prior years' data.We are concerned with how the total frequency response obligation of an interconnection will be determined since this will ultimately determine each BA's FRO. We believe more detail should be presented on this issue.Please make sure enhanced frequency response from load is examined as an economical source of frequency response per FERC requirements in Order 693 paragraphs 336 and 375. The SDT has not addressed how the requirements of the proposed standard can be implemented without a market mechanism.All frequency response available in an RTO/ISO ancillary services market should be offered in a non-discriminatory way (possibly on an OASIS). The standard needs more detail (not an attachment) on how the Interconnect FRO is allocated to BAs. We further suggest the SDT consider providing detail in Attachment A that the Reliability Coordinator will need to be involved in allocation of the FRO to specific regions or plants within the Reliability Coordinator Area. There is a good chance that the proper geographic location of frequency responsive reserves will increase Transfer Path capability when the Transfer Path capability is limited by a loss of generation. This may be the case in the west where loss of two Palo Verde units establishes the California-Oregon Intertie SOL because frequency responsive reserves are carried in the Pacific Northwest, not near Palo Verde. The BAL-003-1 standard does not consider this issue. Please review the (pk gen+pk load)/2 method described in Attachment A, page 3.We appreciate the time and the work performed by the standard drafting team on this standard that we feel is a necessary component for reliable operation of the Interconnections.
Response: The FRO is based on the forecasted values. The SDT had extensive discussions concerning the generation/load split for determining the BA FRO and believes that the proposed methodology is both reasonably equitable and non-discriminatory. The SDT recognizes the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies. The second document will explain the rationale for the requirements as supplemental standard information. This standard provides metrics in which markets and independent solutions can be developed. This standard provides a minimum requirement of a BA but does not prevent an RC from imposing further restrictions. All of the methodologies proposed in this standard are being tested during the field trial.	
SERC OC Standards Review Group	The Standard Authorization Request Form references that BAL-003-0 originated as part of Project 2007-18, Reliability-based Control. Actually, it originated in Project 2007-05, Balancing Authority Control. We are concerned that, in attachment A, the generation/load split in determining FRO may not be the most equitable method

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	for allocation. In general, we feel that Attachment A needs additional clarity, i.e., is the split based on forecasted or prior years' data. We are concerned with how the total frequency response obligation of an interconnection will be determined since this will ultimately determine each BA's FRO. We believe more detail should be presented on this issue. We appreciate the time and the work performed by the standard drafting team on this standard which we feel is a necessary component for reliable operation of the Interconnections."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: Revisions to BAL-003 were originally part of Project 2007-05, but Project 2007-05 was then merged on July 28, 2010 into Project 2007-18. The SDT recognizes the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies. The second document will explain the rationale for the requirements as supplemental standard information. The FRO is based on the forecasted values. The methodologies proposed in this standard have been tested during the field trial.	
South Carolina Electric and Gas	The Standard Authorization Request Form references that BAL-003-0 originated as part of Project 2007-18, Reliability-based Control. Actually, it originated in Project 2007-05, Balancing Authority Control. We are concerned that, in attachment A, the generation/load split in determining FRO may not be the most equitable method for allocation. In general, we feel that Attachment A needs additional clarity, i.e., is the split based on forecasted or prior years' data. We are concerned with how the total frequency response obligation of an interconnection will be determined since this will ultimately determine each BA's FRO. We believe more detail should be presented on this issue.We appreciate the time and the work performed by the standard drafting team on this standard that we feel is a necessary component for reliable operation of the Interconnections.
Response: Revisions to BAL-003 were originally part of Project 2007-05, but Project 2007-05 was then merged on July 28, 2010 into Project 2007-18. The SDT recognizes the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies. The second document will explain the rationale for the requirements as supplemental standard information. The FRO is based on the forecasted values. The methodologies proposed in this standard have been tested during the field trial.	
FirstEnergy	If not already planned, we suggest that the drafting team conduct a webinar on this project to clarify the deliverables and answer questions that industry may have.
Response: The SDT conducted a Webinar on July 18, 2011 and is planning on holding another webinar in November 2011 to explain the changes made between	

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versions.	
Bonneville Power Administration	o D1.4 R1 Supplemental Information (first paragraph) - Adds an additional requirement outside of the requirements section. o D1.4 R2 Supplemental Information (first paragraph) - Adds an additional requirement outside of the requirement section. o D1.4 R Supplemental Information (Second paragraph) - Adds an additional requirement outside of the requirements section. This number has nothing to do with frequency response during events. Also, has more to do with R1 than R2.
Response: The Additional Compliance Section has been completely revised and the issues you identified have been removed.	
SPP Standards Development	The reporting requirement in Attachment A under R1 '...each BA has one month to assemble its data and calculate the FRM.' is not consistent with the reporting requirements in D. Compliance, 1.4 of the draft Standard. R4 - We suggest replacing the word 'increase' with 'modify' or 'adjust'. We also suggest deleting Balancing Authority Area and replacing it with combined areas at the end of the sentence. Why is R4 in BAL-003-0 being retired?
Response: The SDT has corrected the error in the wording. The SDT prefers to use the word “increase” to provide clarity that the Frequency Bias Setting should go up when providing this service. Use of the terms you are suggesting could be interpreted to allow for adjustments up or down. BAL-003-01.b Requirement R4 is not longer necessary. This Requirement addresses how to calculate Frequency Bias Settings. This is no longer needed since the Frequency Bias Settings are calculated in FRS Form 1 using Frequency Response associated with the “official” list of events and a couple of “floor or ceiling” limits (% of peak load/gen and FRO). The entire calculation is built into the FRS Form 1 workbook.	
IRC Standards Review Committee	The sections of “Additional Compliance Information” in the draft standard seem to create requirements as written. For example, revision of 1.4 for R1 Supplemental Information is suggested to be as follows: Each Balancing Authority or the Interconnection designated entity shall reports its previous year’s Frequency Response Measure (FRM) to the ERO on Form 1 by January 10 each year. If the ERO posts the official list of events after December 10, Balancing Authorities or the Interconnection designated entity will be given 45 days from the date the ERO posts the official list of events to submit their FRS Form 1. If aA Balancing Authority may elects to fulfill its Frequency Response Obligation by participating as a member of a Reserve Sharing Group (RSG). If a Balancing Authority elects to report as an RSG, the total of the participating Balancing Authorities’ FRO will be compared to the total of the participating Balancing Authorities’ FRM. Further, revision of 1.4 for R2 Supplemental Information is suggested to be as follows: Each Balancing Authority or the Interconnection designated entity shall reports its current year requested Frequency Bias

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	Setting and Frequency Bias type (fixed or variable) to the ERO on FRS-Form 1 by January 10 each year. If the ERO posts the official list of events after December 10, Balancing Authorities will be given 45 days from the date the ERONERC posts the official list of events to submit their FRS Form 11. Once the FRM and Frequency Bias Settings have been validated by the ERO, the ERO will disseminate the Frequency Bias Settings Report for all Balancing Authorities in each Interconnection along with the implementation date.Balancing Authorities with variable Frequency Bias Settings shall calculate monthly average Frequency Bias Settings. The previous year's monthly averages will be reported annually on FRS Form 1. Again, please clarify what qualifies as "variable" Frequency Bias Setting. Also please clarify how the "monthly average Frequency Bias Settings" are to be calculated. Is it a daily or weekly or hourly weighted average, or something else? In Attachment A: What is the "frequency deviation event threshold specified for the Interconnection"? Where is it specified? Please clarify.In Attachment A, 2.b.: Is this intended to be describing Point B? Please clarify.In Attachment A: While the ERO is deciding which events to use, does this mean that, throughout the year, the BA must collect and save all the relevant data for all events so as to have the data ready and available for when the ERO issues the list of events to be reported? In Attachment A, 4.: "Any indication or evidence of a secondary event occurrence after Point C should be reviewed for inclusion based on having sufficient information to perform a full analysis of the event". What meant by "should be reviewed"? Who is to be doing the review? What are the criteria for the review? In the Implementation Plan: "native load" is not defined in the ERCOT Interconnection. Please clarify.
Response: The Additional Compliance Section has been completely revised and the issues you identified have been removed. The Requirement and Measure have been modified to include references to RSGs. Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions. The SDT recognizes the need to convert Attachment A into two documents in order to provide further clarity. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies. The second document will explain the rationale for the requirements as supplemental standard information. The current Reliability Standard BAL-005 cites the data required to be archived. As envisioned, the ERO will post the events to be analyzed on a quarterly basis to allow a BA to review its performance throughout the year. The Implementation Plan no longer references "Native Load". However, this term is defined in the NERC Glossary of Terms.	
ERCOT	The sections of "Additional Compliance Information" in the draft standard seem to create requirements as written. For example, revision of 1.4 for R1 Supplemental Information is suggested to be as follows: Each Balancing Authority or the Interconnection designated entity shall reports its previous year's Frequency Response Measure (FRM) to the ERO on Form

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	1 by January 10 each year. If the ERO posts the official list of events after December 10, Balancing Authorities or the Interconnection designated entity will be given 45 days from the date the ERO posts the official list of events to submit their FRS Form 1. If aA Balancing Authority may elects to fulfill its Frequency Response Obligation by participating as a member of a Reserve Sharing Group (RSG). If a Balancing Authority elects to report as an RSG, the total of the participating Balancing Authorities' FRO will be compared to the total of the participating Balancing Authorities' FRM.Further, revision of 1.4 for R2 Supplemental Information is suggested to be as follows:Each Balancing Authority or the Interconnection designated entity shall reports its current year requested Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO on FRS-Form 1 by January 10 each year. If the ERO posts the official list of events after December 10, Balancing Authorities will be given 45 days from the date the ERONERC posts the official list of events to submit their FRS Form 11. Once the FRM and Frequency Bias Settings have been validated by the ERO, the ERO will disseminate the Frequency Bias Settings Report for all Balancing Authorities in each Interconnection along with the implementation date. Balancing Authorities with variable Frequency Bias Settings shall calculate monthly average Frequency Bias Settings. The previous year's monthly averages will be reported annually on FRS Form 1. Again, please clarify what qualifies as "variable" Frequency Bias Setting. Also please clarify how the "monthly average Frequency Bias Settings" are to be calculated. Is it a daily or weekly or hourly weighted average, or something else?In Attachment A: What is the "frequency deviation event threshold specified for the Interconnection"? Where is it specified? Please clarify.In Attachment A, 2.b.: Is this intended to be describing Point B? Please clarify.In Attachment A: While the ERO is deciding which events to use, does this mean that, throughout the year, the BA must collect and save all the relevant data for all events so as to have the data ready and available for when the ERO issues the list of events to be reported?In Attachment A, 4.: "Any indication or evidence of a secondary event occurrence after Point C should be reviewed for inclusion based on having sufficient information to perform a full analysis of the event". What meant by "should be reviewed"? Who is to be doing the review? What are the criteria for the review?In the Implementation Plan: "native load" is not defined in the ERCOT Interconnection. Please clarify.

Response: The Additional Compliance Section has been completely revised and the issues you identified have been removed.

The Requirement and Measure have been modified to include references to RSGs.

Variable frequency bias settings are determined by Balancing Authorities using a calculation based on present operating conditions.

The SDT recognizes the need to convert Attachment A into two documents in order to provide further clarity. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies. The second document will explain the rationale for the requirements as supplemental standard information.

The current Reliability Standard BAL-005 cites the data required to be archived.

As envisioned, the ERO will post the events to be analyzed on a quarterly basis to allow a BA to review its performance throughout the year.

The Implementation Plan no longer references "Native Load". However, this term is defined in the NERC Glossary of Terms.

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Progress Energy	We believe this standard insufficiently addresses the true nature of the problem; however it does accuratly address the fact

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	that the current BA minimum frequency bias setting is too large. This standard should also exclude LSE's without generation capacity since this problem both exists and can be solved at the generator level.
Response: The SDT agrees that the generator level can solve the issues. This standard is addressing directives from FERC Order 693. Any reference to a generator requirement would be outside of the industry approved SAR. The LSE is not cited as an applicable entity.	
NIPSCO	We reviewed the number of BAs in the Eastern Interconnection and there are many. We're hoping that compliance to R1 would be covered by the RSGs similar to DCS.
Response: The SDT added the RSG as a applicable entity to allow a BA an alternative method for complying with this standard.	
Energy Mark, Inc.	Comment 55: In Comment 25 I indicated that the suggested allocation method creates perverse incentives for BAs attempting to make decisions concerning Frequency Response. My comments here support that contention. Since the suggested allocation method is blind to changes in the demand for Frequency Response and it allocates the requirement to supply Frequency Response on a fixed Peak Load / Peak Generation Ratio share, it supports economic decisions at the BA level that are far from economic at the interconnection level. This perverse influence on economics and reliability are illustrated with two examples. Example 1: A BA with a Peak Load / Peak Generation Ratio share of 5% of the interconnection must decide whether or not to implement a program to expend $1 M to reduce the demand for Frequency Response worth approximately a comparable $5 M. From an interconnection level this is an obvious decision. The BA should implement the program. However, when the allocation method is considered, if the BA implements the program, it will expend $1 M, but will only see a reduction in its Frequency Response requirement of $.25 M. The remainder of the reduction in demand for Frequency Response will be shared by the other BAs on the interconnection. Therefore, it is in the BAs interest to not implement the program even though it provides excellent overall economics and results in improved reliability. Example 2: A BA with a Peak Load / Peak Generation Ratio share of 5% of the interconnection must decide whether or not to implement a program to save $1 M in annual maintenance expenses at its generation plants that will increase the need for Frequency Response on the interconnection at an annual cost of $5 M. From an interconnection level this is an obvious decision. The BA should not implement the program. However, when the allocation method is considered, if the BA implements the program, it will save $1 M anually, but will only see a increase in its annual expense for Frequency Response requirement of $.25 M. The remainder of the increase in demand for Frequency Response will be shared by the other BAs on the interconnection. Therefore, it is in the BAs interest to implement the program even though it fails to provide good economics and results in a decline in reliability. These examples demonstrate why a fixed allocation method as suggested in Attachment A would result in perverse results

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	with respect to reliability and economics. Comment 56: A series of four technical papers were written and offered to the Frequency Response Standard Drafting Team that describe a measurement method for Frequency Response that does not have the detrimental limitations that exist with the Peak Load / Peak Generation Ratio share method suggested in Attachment A. These four paper are:1. Illian, H. F., Frequency Response Risk Measure, Prepared for the Frequency Response Standard Drafting Team, Energy Mark, July 1, 2010 revised September 7, 2010.2. Illian, H. F., Understanding ACE and CPS1, Prepared for the Frequency Response Standard Drafting Team, Energy Mark, September 8, 2010.3. Illian, H. F., Frequency Response Reliability Measure for the Balancing Authority, Prepared for the Frequency Response Standard Drafting Team, Energy Mark, October 11, 2010.4. Illian, H. F., Description of Regressions for Frequency Response Analysis, Prepared for the Frequency Response Standard Drafting Team, Energy Mark, September 21, 2010.PDFs of these papers have been forwarded to supplement these comments and should be addended as part of my comments.
Response: Comment 54 – The SDT understands your concerns and has taken them under consideration during the development of this standard. The SDT will provide technical justification for the methods it proposes within the standard. Comment 55 – The SDT thanks you for your work in creating the aforementioned papers. The SDT has reviewed these papers and considered them during the development of this standard. Furthermore, the SDT will forward them on to the appropriate NERC personnel.	
Hydro-Quebec TransEnergie	The proposed NERC standard (BAL-003) does not take into account the “point C” issue. The proposed requirements are only related to “point B”.The proposed NERC standard (BAL-003) validates that the Balancing Authority carries enough Synchronized Reserve and that this reserve is really Frequency Responsive, on average in the most common situations (based on the median). It is an “after-the-fact” evaluation of the performance of the Balancing Authority. However, there is no guaranty that the Balancing Authority will maintain the required Synchronized Reserve either when the load is very low or during peak load periods Real-time Monitoring of the frequency responsive reserve would be a good way to avoid this issue.
Response: The SDT is proposing a more conservative Point B result in order to protect for Point C UFLS. We encourage real-time monitoring of Frequency Response as a good practice but mandating it is beyond industry approved SAR. Also, the SDT believes that this is being addressed in the development of the Balancing Authority Reliability-based Control standards in Project 2010-14.	
Westar Energy	Based on a Category C (N-2) event, what is the approximate Interconnection Frequency Response Obligation for each Interconnection? What is the First Step UFLS for each Interconnection? Since there is no NERC Standard requirement for what first step UFLS is, what if it changes during the year?
Response: The SDT recognized the need to convert Attachment A into two documents. The first document will remain part of the standard as Attachment A and provide greater detail for the calculation methodologies, including FRO. The second document will explain the rationale for the requirements as supplemental standard information. Table 2 in revised Attachment A shows the FRO for each interconnection and the methodology used to determine this value. The UFLS set point used in the calculation is shown in Table 2 for each Interconnection. These values are intended to protect against frequency reaching the highest UFLS	

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setting for credible contingencies. The utilities have the ability to change the UFLS settings during the year. The entities FRO and Frequency Bias Setting would remain the same until it was reviewed by the ERO. Your comment does emphasize the need for the ERO to coordinate these changes across standards but this is outside the scope of this project..	
EKPC	EKPC would like to express the importance of considering large non-conforming loads and their effects on smaller BAs.We appreciate the drafting team's effort and dedication to this standard.
Response: The SDT has modified FRS form 1 to allow for adjustments, including non-conforming load.	
We Energies	The FRO and the standard in general focus on Frequency Response for an intact grid. Inadequate consideration is given to unexpected events such as separation, islanding and partial or total BES failure. In these cases, the location of the FR resources is important. For example, if a BA has a contract with an entity that controls load level to satisfy the required FRO, that load may not be within the island created following a disruption to the BES. A complete BES failure may leave a black start island with only load frequency response. Load frequency response is the ultimate dispersed source for this commodity, but may be inadequate as the sole provider under abnormal grid conditions. For better grid security, other dispersed sources of frequency response are desirable. Comment on the NERC Resources Subcommittee Position Paper on Frequency Response (Discussion Draft):EOP-005-2 does not contain requirements for the Balancing Authority in a restoration event involving the use of black start resources. Only Transmission Operators, Generator Operators, Transmission Owners identified in the Transmission Operators restoration plan, and Distribution Providers identified in the Transmission Operators restoration plan have roles in that standard. How will the BA "bring more Frequency Responsive resources to bear" during black start if they have no defined role?
Response: This standard is not meant to be an emergency operations standard. However, this standard could assist an entity in identifying and solving the problem you have mentioned. The NERC RS Position Paper on Frequency Response is not a product of this standard. It is an information paper requested by the NERC OC. The RS posted the document and received industry comments that were incorporated.	
American Electric Power	If a balancing authority loses generation, what happen to the neighboring balancing authority's AGC? If an overall Reserve Sharing Group's performance can possibly be used to meet performance measures, why is the RSG not included in the Standard applicability for such functional entity?
Response: If the Frequency Bias Setting is close to natural Frequency Response, as this standard is proposing, the AGC impacts would be minimal or none. The RSG is listed in the Applicability Section of this standard. The SDT has further modified Requirement R1 to identify the RSG within the requirement.	

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Duke Energy	Below are just some of the points that Duke Energy believes need to be discussed further. Relationship to other standards under development: Given the significant implications of this standard to the other balancing-related standards, Duke Energy feels strongly that the Standards Committee should keep the work under Project 2010-14, Balancing Authority Reliability-based Control, high on the list of standards to be developed. CPS1 and the proposed BAAL are measures that make sense in the long term, as they provide “support to maintain Interconnection Frequency within predefined bounds” and aid in “supporting frequency until the frequency is restored to schedule” as desired in the purpose statement of this standard. Reserve Sharing Group: Duke Energy understands and supports the concept that Frequency Response could be aggregated over a Reserve Sharing Group, however the details need to be addressed in the measures, and in the requirements, which in the current draft only apply to the Balancing Authority. Field test: Duke Energy found the implementation plan and field test confusing. The information didn’t indicate when the field test would start and end. The implementation plan proposes starting the gradual adjustment of BAL-003-0 R5 in May 2011 - what if the standard hasn’t been approved by FERC by then? Shouldn’t those dates be tied somehow to the effective date of BAL-003-1 which is in turn tied to regulatory approval where required? Or is that gradual decrease actually part of the field test? Frequency responsive resources: What are the attributes needed for a resource, or combination of resources, to be considered capable of providing “Frequency Response”? The answer is a critical element to the development of market products in a uniform manner across the Interconnection. Among other attributes, Frequency Response aids in arresting sudden frequency decline, however frequency responsive resources must respond to positive and negative deviations in Interconnection frequency. Having loads that drop off the system at certain levels of frequency are valuable tools in arresting frequency decline, however such resources do nothing within the range of frequency in which the Interconnection operates perhaps 99% of the time. This would point to perhaps two types of services to address frequency below 60 Hz - provision of frequency response in normal and emergency operation, and provision of a service specific for arresting a significant drop in frequency at a specific bound to reduce the possibility of UFLS needing to be utilized. Duke Energy believes these are two different products and should not be considered interchangeable. Methods of obtaining Frequency Response: If frequency response is a market resource, how can it be attained or scheduled from another Balancing Authority? Duke Energy believes this question needs to be asked of the Interchange Subcommittee. As the concept of a Reserve Sharing Group providing a “group frequency response” would not in our opinion constitute “interchange”, Duke Energy believes the measure for calculated response should look at the RSG as if it was a single BA, rather than attempt to measure the RSG participants individually. On the other hand, outside of an RSG, if resources in one BA Area were contracted to supplement the response of resources in another BA Area, would such response be provision of a service between a source and sink BA, or would it be interchange with the Interconnection in some manner? FRM calculation:

Organization	Question 17 Comment
	Under the proposed definition, the FRM calculation would only consider provision of response from resources external to the BA Area if the "interchange" came in the form of a Pseudo-tie adjustment to Actual Interchange - Dynamic Schedules would not be accounted for. As the use of Pseudo-ties changes load calculations and other data, even the use of them may not make sense compared perhaps to just having a mechanism to move the obligation to the area providing the response, and then determining if the provision of just Frequency Response must absolutely carry into increased secondary control requirements. Separating primary response from secondary control: Is it possible for resources in one BA to provide a measure of Frequency Response for another BA, but not result in a change to each BA's Frequency Bias Setting used in the secondary control requirements?
Response: The development of the Balancing Authority Reliability-based Control standards in Project 2010-14 are outside the scope of this SDT, however the need to coordinate development was raised with the Standards Committee and the standards in Project 2010-14 that address "reserves" have been advanced as high priority. The SDT has modified Requirement R1 and the associated measure to identify the RSG. In reference to your field trial comment the SDT has modified the Implementation Plan to no longer reference the field test or the reduction of the minimum Frequency Bias Setting. The SDT has developed a process by which the ERO will reduce the minimum Frequency Bias Setting. The procedure used to reduce the Frequency Bias Setting is detailed in Attachment B and is now tied to regulatory approval of this standard. This standard will provide the metrics for Frequency Response while the market will define itself. The SDT encourages you to work with NAESB to define a market. The SDT encourages you to open a discussion with the Interchange Subcommittee concerning Frequency Response as a market resource. The SDT has included language that defines how the RSG is to perform and comply with this standard. The SDT agrees that a Reserve Sharing Group providing a "group frequency response" would not be interchange between the entities within that group. The SDT also agrees that the RSG would be evaluated as if it were a single BA. The SDT has incorporated an improved FRS Form 1 with instructions for its use. The SDT thanks you for your comment concerning Pseudo-tie but, based on the information provided, the SDT is unsure of your question and cannot provide a further response. With regards to your last comment, the SDT believes that it is possible as long as they are using a dynamic schedule.	
Patterson Consulting, Inc.	Requirement 4 is worded incorrectly, although it is taken from the existing standard. Requirement 4 states "Each Balancing Authority that is performing Overlap Regulation Service shall [increase] its Frequency Bias Setting in its ACE calculation by combining the Frequency Bias Settings for the entire Baalancing Authority Area being controlled." (Bracketing added for emphasis.) Considering Frequency Bias Settings are negative numbers, this requirement should have Balancing Authorities "decrease" rather than "increase" their Frequency Bias Settings. For example, the requirement could state "Each Balancing Authority that is performing Overlap Regulation Service shall decrease..." or if "decrease" is undesirable then "Each Balancing Authority that is performing Overlap Regulation Service shall modify..."

Organization	Question 17 Comment
Response: The SDT understands your concern with the use of the term "increase" and has replaced this word with "modify". The SDT revised Requirement R4 for additional clarity and it now reads: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO or calculate the Frequency Bias Setting based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled.	
Associated Electric Cooperative, Inc.	BAL-003-1 draft standard: Apparent Intent and expectations: 1) I agree with this emerging standard's recognizing that the arbitrary 1% of peak-load should be refined by being lowered to better reflect each BA's expected frequency response. 2) This emerging standard apparently attempts to address the divesture of generation from loads by utilizing the "(Load + Generation)/2" formula, which seems fair. 3) I'm still struggling with the concept of being able to share in the success of an RSG, but not its failures if your BA was individually successful. Something seems wrong with that approach. However if necessary, AECI will definitely use it to its advantage. 4) I really would have liked to see the Measures that are currently in draft. Comment on Definitions: 1) SEFRD - I had to read this definition several times because "The individual sample of event data" is actually an internally calculated value derived from a set of event sample data, and not really a "sample" value at all. So, I believe the SEFRD definition needs further work. 2) FRM is defined by undefined terms "FRS" and "FRS Form 1". 3) FRO – fine 4) FRS - "Frequency Response Survey" Requirements and Requirements Supplement Information1) R1 and R1 Supplemental Information, pp 2, 4 a) I believe these two sections should be combined into one requirement, specifying the basic BA requirement "or, if the BA was within an RSG and elects to report from within that RSG's performance," that RSG's performance requirement. b) The time-frame for reporting should be another requirement, and with a companion Measurement. (Concerning the timing, the original response timeframe is 31 days, but the if NERC slips past the "normal" December 10 deadline, the

Organization	Question 17 Comment
	response time requirement is increased by 50%, to 45 days? Did somebody make a mistake, or was this intentional?) c) The problem with this requirement is that it relies on each BA to "read" its own frequency-performance, and does not provide a clear system of comparison between BAs for the same frequency event. In other words, the drafting team is trying to impose a nice bright-line objective standard, that is really resting on what is currently a very subjective calculation of SEFRD. . (See item 3, Rx- below) 2) R2 and R2 Supplemental Information pp 2..4 a) See comment 1.b above, concerning reporting time-frame being another requirement b) I believe every BA should report its monthly average frequency-bias setting, whether fixed-bias or variable-bias. In the case of reporting fixed-bias, the first two months will likely be different from the remaining ten months within the same calendar year. 3) Rx - I believe there is a hidden requirement, that the ERO monitor each interconnection's frequency for candidate events, then annually select and provide the top events for FRS Form 1 reporting. That same requirement should dictate that the ERO provide the corresponding A, B, and C times for each FRS Form 1 reportable event, when the survey goes out. I believe this requirement should be spelled-out, in order to improve reporting consistency and make the FRS reporting process a bit more objective.

Response: "Apparent Intent"

Comments 1) & 2) – The SDT thanks you for your comment.

Comment 3) The SDT added the RSG as a applicable entity to allow a BA an alternative method for complying with this standard. The SDT has included language that defines how the RSG is to perform and comply with this standard.

Comment 4) The SDT purposely left the measures out of the first draft. This was to ensure the focus would be on the requirements themselves. The SDT also recognized that the requirements would probably need revision after receiving industry feedback.

Definitions:

Comment 1) The SDT agrees with your concern regarding the definition of SEFRD. The SDT has removed the definition from the standard.

Comment 2) The term FRS Form 1 is only identifying a form to be used when providing information to the ERO.

Comment 3) The SDT thanks you for your agreement with the definition.

Comment 4) Again, the term FRS is simply pointing to a particular for to be used when providing the information to the ERO.

Requirements:

Comment 1 a) The SDT has revised Requirement R1 to reference an RSG. The Requirement now reads "Each Balancing Authority (BA) or Reserve Sharing Group (RSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of

Organization	Question 17 Comment	
Frequency Response in the Interconnection.” Comment 1 b) The Additional Compliance Section has been completely revised and the issues you identified have been removed. Comment 1 c) The revised standard changes the methodology from subjective to directed. Comment 2 a) The Additional Compliance Section has been completely revised and the issues you identified have been removed. The SDT has corrected the timing issue you have referenced. Comment 2 b) The SDT disagrees and believes that “fixed” should be reported on a annual basis while “variable” should be reported monthly due to the nature of the calculation. Comment 3) The SDT believes that Point C is not needed for the methodology being recommended. The revised FRS Form 1 and the new Form 2 provide clarification concerning Point A and Point B.		
Alberta Electric System Operator	Is there any relation or coordination between the work of this standard and the effort on "NERC RS Position Paper on Frequency Response" ? The AESO believes these two projects should be coordinated.The AESO has also signed on to comments submitted by the SRC. We see the SRC comments as continent wide and these AESO comments as more Alberta specific.	
Response: The NERC RS Position Paper on Frequency Response is not a product of this standard. It is an information paper requested by the NERC OC. The RS posted the document and received industry comments that were incorporated. In addition, some of the Frequency Response SDT membership are also members of the NERC RS. Please refer to our comments to SRC.		
Kansas City Power & Light		No other comments.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-12 Frequency Response

The Frequency Response Drafting Team thanks all commenters who submitted comments on the first formal posting for Project 2007-12 Frequency Response. This standard was posted for a 45-day public comment period from October 25, 2011 through December 9, 2011. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 133 different people from approximately 86 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

Based on the comments received and the drafting team's discussion of those comments, the drafting team made the following changes to the proposed Standard, definitions, and associated documents:

- Modified the definition for Frequency Response Measure (FRM)
- Modified the definition of Frequency Bias Setting
- Removed the references to Reserve Sharing Groups (RSGs) and replaced them with Frequency Response Sharing Group
- Created a definition for Frequency Response Sharing Group (FRSG)
- Modified Requirement R2 to provide clarity and incorporate Requirement R5
- Created a new Requirement R3 for entities using variable Frequency Bias
- Removed the requirement for operating in Tie Line Bias mode as duplicative of other requirements in other standards
- Removed Requirement R5 and combined it into revised Requirement R2 and new Requirement R3
- Modified Attachment A to provide additional clarity
- Created a Procedure to provide instructions for the ERO to follow in supporting the standard
- Made conforming changes to Measures, Evidence Retention, and VSLs to align with language in the revised requirements
- Re-wrote the Background Document to incorporate additional language for justification of requirements and provide additional clarity
- The SDT is now using the method detailed in the Frequency Response Initiative Report dated September 30, 2012 to calculate the Interconnection Frequency Response Obligation.

There were some minority issues that the team was unable to resolve, including the following:

- A few stakeholders questioned a Requirement for the BA to provide Frequency Response when they typically do not own generation. The SDT explained that the NERC Functional Model and FERC cited the BA as the responsible party for providing Frequency Response and that this was outside the scope of the industry approved SAR. The SDT also stated that there were several different methods available to the BA to provide Frequency Response and that the SDT had included these in the Background Document. The SDT further stated that any entity could submit a SAR addressing this issue to the SC for consideration and that the SDT supported this option.
- A couple of the commenters felt that the median was not the proper method to use for the calculation of the FRM and that the RSG was not fully explained. The SDT stated that the statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response. The SDT also noted that while the median was not perfect, the median approaches a BA's typical performance after 15-20 observations and that more observations give a higher confidence in the estimate of the BA's performance.
- Some commenters disagreed with proceeding through development of the standard before the proposed measures have been thoroughly field tested. The SDT stated that it was responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.

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

http://www.nerc.com/filez/standards/Frequency_Response.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Murphey	BPA	WECC	1
2.	Bart McManus	BPA	WECC	1
3.	David Kirsch	BPA	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Cathy Bretz		IID	WECC 6										
3.	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.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	David Kiguel	Nydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	Neqw Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Will Smith	MRO NSRF										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1

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

3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	NSP (XCEL)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	RICHARD BURT	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andy Burch	EEI	SERC	5
2.	Bob Dalrymple	TVA	SERC	1, 3, 5, 6
3.	Brad Gordon	PJM	SERC	2
4.	Vicky Budreau	SCPSA	SERC	1, 3, 5, 6
5.	Sam Holeman	Duke	SERC	6, 1, 3, 5
6.	Cindy Martin	Southern Co	SERC	1, 5
7.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
8.	Wayne Van Liere	LGE-KU	SERC	3
9.	Larry Akens	TVA	SERC	1, 3, 5, 6
10.	John Troha	SERC Reliability Corp.	SERC	10

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 3, 5
2.	David Dockery	Assocoated Electric Cooperative	SERC	1, 3, 5

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

3. Lisa Duffey	Cleco Power	SPP	1, 3, 5
4. Jonathan Hayes	SPP	SPP	2
5. Steve Haun	Lincoln Electric System	MRO	1, 3, 5
6. Tony McMurtry	Lafayette Utilities System	SPP	NA
7. Dave Milliam	Kansas City Power & Light	SPP	1, 3, 5, 6
8. Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
9. Katie Shea	Westar Energy	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

Additional Member	Additional Organization	Region	Segment Selection
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2. Greg Woessner	Kissimmee Utility Authority	FRCC	3
3. Jim Howard	Lakeland Electric	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Joe Stonecipher	Beaches Energy Services	FRCC	1
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7. Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Thomas McElhinney	JEA Electric Compliance	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. John Babik	JEA Electric Compliance	FRCC	5
2. Ted Hobson	JEA Electric Compliance	FRCC	1
3. Garry Baker	JEA System Operations	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Al DiCaprio	ISO/RTO Council Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Charles Yeung	SPP	SPP	2
2. Kathleen Goodman	ISO-NE	NPCC	2
3. Gary DeShazo	CAISO	WECC	2
4. Greg Campoli	NYISO	NPCC	2
5. Steve Myers	ERCOT	ERCOT	2

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

6. Don Weaver	NBSO	NPCC	2
7. Mark Thompson	AESO	WECC	2
8. Ben Li	IESO	NPCC	2

				1	2	3	4	5	6	7	8	9	10
11.	Group	Jason L. Marshall	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 5, 6
2. James Jones	Arizona Electric Power Cooperative/Southwest Transmission Cooperative	WECC	1, 5, 6
3. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
12.	Group	Joe Tarantino	Sacramento Municipal Utility District (SMUD)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kevin Smith	Balancing Authority of Northern California (BANC)	WECC	1

				1	2	3	4	5	6	7	8	9	10
13.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
14.	Individual	Cindy Oder	Salt River Project	X		X		X	X				
15.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
16.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
17.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
18.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
19.	Individual	Don McInnis	Florida Power & Light Company	X		X		X					
20.	Individual	Carlos J. Macias	FPL	X		X		X	X				
21.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
22.	Individual	Thomas Washburn	FMPP						X				
23.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
24.	Individual	Kathleen Goodman	ISO New England Inc		X								
25.	Individual	John Tolo	Tucson Electric Power	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X				
27.	Individual	Michael Falvo	Independent Electricity System Operator		X								
28.	Individual	John Bussman	Associated Electric Cooperative Inc	X		X		X	X				
29.	Individual	Rich Salgo	NV Energy	X		X		X					
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
32.	Individual	Louis C. Guidry	Cleco Corporation	X		X		X	X				
33.	Individual	H. Steven Myers	ERCOT		X								
34.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
35.	Individual	Curtis Crews	Texas Reliability Entity										X
36.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
37.	Individual	Anthony Jablonski	ReliabilityFirst										X
38.	Individual	Brenda Powell	Constellation Energy Commodities Group						X				
39.	Individual	Kirit Shah	Ameren	X		X		X	X				
40.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
41.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
42.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
43.	Individual	Robert Blohm	Keen Resources Asia Ltd.								X		

1. **The SDT has made minor modifications to the proposed definitions to provide additional clarity. Do you agree that these modifications provide sufficient clarity? If not, please explain in the comment area.**

Summary Consideration: The majority of the commenters felt that the SDT should use the term "prevent" instead of "discourage" in the definition of FRM. The SDT explained that it did not want to use the word "prevent" since the SDT believes that the word would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage it.

Many of the commenters did not agree with requiring the BA to provide Frequency Response. The NERC Functional Model and FERC cite the BA as the responsible party for providing Frequency Response. There are several different methods available to the BA to provide Frequency Response and these are included in the Background Document.

A couple of the commenters felt that the median was not the proper method to use for the calculation of the FRM and that the RSG was not fully explained. Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response. While the median is not perfect, the median approaches a BA's typical performance after 15-20 observations and more observations give a higher confidence in the estimate of the BA's performance.

Some commenters had concerns about the use of the RSG as a means to provide Frequency Response, and in response the SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Organization	Yes or No	Question 1 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend the following change to the definition of Frequency Bias Setting. LADWP believes that this change increases the clarity of the definition: Original 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's Frequency Response contribution to the

Organization	Yes or No	Question 1 Comment
		Interconnection, and discourage response withdrawal through secondary control systems. Proposed Change 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's Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems
Response: The SDT disagrees with your definition. The SDT considered using the term "prevent" but decided to use the term "discourage" instead. The SDT believes that the word "prevent" would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.		
Alliant Energy Corp. Services, Inc.	Negative	The definition of Frequency Bias Setting should focus on what it is. balancing Authorities do not supply energy. seggest rivising it to "A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area."
Response: The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not**		

Organization	Yes or No	Question 1 Comment
outweigh the effort and cost. **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has chosen to use.**		
Potomac Electric Power Co.	Negative	The proposed new Definitions do not stand alone and are also linked to Attachments.
Response: The SDT has modified the definitions to no longer reference any other documents.		
ISO/RTO Council Standards Review Committee	No	(1) In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That's fair enough. However, the FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an Attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/approval process without any appreciable value.Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body itself. This will eliminate that cross reference issue. After all, the definition for FRM is a simple

Organization	Yes or No	Question 1 Comment
		sentence and does not provide any clarity or specific details that cannot be presented by using appropriate wording in a requirement. (2) The definition of Frequency Bias Setting, if retained, should focus on what it is. Balancing Authorities do not supply energy. We suggest to revise it to: Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's (BA's) Area Control Error (ACE) equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area.

Response: The SDT believes that these terms will be used in later version of the BAL Standards. The term FRO is presently being used in the development of a new standard (BAL-012-1 Planning Reserves). The SDT has modified the definitions to no longer reference any other documents.

The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.

There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.

Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.

The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has

Organization	Yes or No	Question 1 Comment
chosen to use.		
Duke Energy	No	Duke Energy would suggest removing "usually" from the Frequency Bias Setting definition, as the value in the ACE equation must be in terms of MW/0.1Hz in order for ACE to be correctly calculated. We apologize for missing this point in the last round of comments. Though some would argue that the last phrase of the definition is more of an explanation of a function rather than a definition, we support keeping the phrase inserted, as it should be recognized that the intent is to account for the frequency response contribution AND keep the FBS slightly larger (in magnitude) than the average estimated response, to better discourage withdrawal, which was also recognized by Nathan Cohn. Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?
Response: It is the understanding of the SDT that EMS systems could use different methods implementing the ACE calculation. The SDT therefore believes that the term "usually" is more appropriate. **The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."**		
Independent Electricity System Operator	No	In our previous comments, we suggested to drop the definitions for the terms FRM and FRO in favor of providing the needed wording in the standard itself to take care of the specific details. The SDT did not adopt our suggestion with the reason that these definitions will be used by other standards in the future. That's fair enough. However, the FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a

Organization	Yes or No	Question 1 Comment
		definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/maintenance problem without any appreciable value. Once again, we strongly urge the SDT to consider dropping these definitions, and have the details fully specified in the standard body. This will eliminate the cross reference issues. After all, the definition for FRM is a simple sentence and does not provide any clarity or specific details that cannot be addressed by providing the appropriate wording in a requirement. With this cross-reference issue, combined with the issues associated with Attachments A and B (see our comments under Q6, below), we are unable to support this standard at this time.
Response: The SDT believes that these terms will be used in later version of the BAL Standards. The term FRO is presently being used in the development of a new standard (BAL-012-1 Planning Reserves). The SDT has modified the definitions to no longer reference any other documents.		
Keen Resources Asia Ltd.	No	In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because--it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control;--it is non-linear; and therefore--it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median:

Organization	Yes or No	Question 1 Comment
		in other words, the RSG's median cannot represent the sum of the medians of its members.The last paragraph on page 5 of the Background Document is patently wrong, invented, and supported in no probability & statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticians use the median as the best measure of central tendency when a population has outliers." (See http://www.robertblohm.com/BestStatistic.doc for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution. They are distinct from the normal operating errors that are the subject of CPM control. The paragraph does correctly conclude that the linear regression more accurately incorporates outliers than the median does, although the paragraph uses rhetoric by calling this improvement "skew" as if it is distortionary when, in fact, the median distorts the reality.

Response: The word "average" is a generic term to represent central tendency. The term is often used synonymously with the arithmetic "mean".
The issue with measuring frequency response is that a BA's calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.

Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the East typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute load changes can easily wash this contribution out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.

Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response.

A regression would be appropriate if you were trying to forecast "calculated" frequency response for a BA in a multi-BA

Organization	Yes or No	Question 1 Comment
interconnection. **While not perfect, the median approaches a BA's typical performance after 15-20 observations. More observations give a higher confidence in the estimate of the BA's performance.**		
Manitoba Hydro	No	It is not clear why the term "Single Event Frequency Response Data (SEFRD)" has been removed from the standard but is still used and defined in the Background Document and Attachment A.
Response: The SDT removed the term because it was not being used within the standard itself. It was only being used in the calculation of the FRM. There is no need to create a NERC Glossary defined term if it is not being used in the standard.		
Seattle City Light	No	LADWP and SCL recommend the following change (in red) to the definition of Frequency Bias Setting. LADWP believes that this change increases the clarity of the definition:OriginalA 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's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.Proposed ChangeA 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's Frequency Response contribution to the Interconnection, and discourage prevent response withdrawal through secondary control systems
Response: The SDT disagrees with your definition The SDT considered using the term "prevent" but decided to use the term "discourage" instead. The SDT believes that the word "prevent" would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.		
Los Angeles Department of Water and Power	No	LADWP recommends the following change to the definition of Frequency Bias Setting (replace the word "discourage" with the word "prevent"). LADWP believes that this change increases the clarity of the definition:OriginalA number, either fixed or variable, usually expressed in

Organization	Yes or No	Question 1 Comment
		MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.Proposed ChangeA 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's Frequency Response contribution to the Interconnection, and prevent response withdrawal through secondary control systems
Response: The SDT disagrees with your definition. The SDT considered using the term "prevent" but decided to use the term "discourage" instead. The SDT believes that the word "prevent" would imply that you could stop withdrawal. The SDT does not believe that you can totally stop the withdrawal but you can discourage withdrawal.		
Progress Energy	No	PGN supports the collective comments of SERC members.We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?
Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to not further modify the definition based on your comments. **The SDT has modified the definition for FRM to state that it is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."**		
ERCOT	No	RE: Frequency Response Obligation (FRO) definition: ERCOT suggests changing "Balancing Authority's" to "Balancing Authority Area's" as follows:

Organization	Yes or No	Question 1 Comment
		The Balancing Authority Area's share of the required Frequency Response needed for the reliable operation of an Interconnection. A BA that does not own generation resources cannot provide Frequency Response, it can only schedule and dispatch available resources capable of such; . The BA should be responsible for taking action to schedule resources that are capable of frequency response, and monitoring to assure frequency response performance. The GOP (possibly the LSE when demand side performance is involved) must be accountable for performing.However, there is nothing in this requirement to encourage the owner of a resource who chooses not to provide frequency response to come to the table. There is nothing in this standard that uniformly requires all frequency response providers to perform. This is likely to be detrimental to the performance of a BAA and unfairly sanctions those willing to perform to to assure reliability while others are not required to perform.
Response: The SDT believes that the BA is the responsible entity not the BA Area. **The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.** **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a**		

Organization	Yes or No	Question 1 Comment
need for a generator performance obligation, they are encouraged to submit a SAR to that effect.		
Ameren	No	The Frequency Response Measure (FRM) definition should include which Entity(ies) it applies to, similar to the definition of the FRO.
Response: The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."		
Constellation Energy Commodities Group	No	The Frequency Response Obligation has two components based on Attachment 1 - an Interconnection FRO and a BA FRO. The proposed definition captures only the BA FRO.
Response: The definition is referencing the responsible entity, the BA. The interconnection's FRO is only calculated as the beginning point for the determination of the BA's FRO.		
Hydro-Quebec TransEnergie	No	The FRM and FRO definitions should precise that it is expressed in MW/0.1Hz. As for the Frequency Bias Setting definition, as written, would apply only to a multiple BA Interconnection. In a single BA Interconnection, the Frequency Bias translates the frequency error into a MW value that must be dispatched to bring back Frequency to desired value. Since Tie Lines are not controlled through AGC, there is no response withdrawal issue
Response: The FRM and FRO definitions have been modified to state MW/0.1Hz. **The SDT disagrees. There can be withdrawal on any interconnection that uses a Frequency Bias estimate if that estimate is lower than Frequency Response and other factors are used to determine dispatch, i.e., future load estimate.**		
Northeast Power Coordinating Council/ISO New England Inc.	No	The FRM definition should not refer to FORM 1. Also, suggest the following wording for frequency bias setting: "A number,

Organization	Yes or No	Question 1 Comment
		either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to approximate the frequency response provided by the assets within the respective Balancing Authority's area."
Response: The SDT has modified the definitions to no longer reference any other documents. **The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."** **The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.** **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has chosen to use.**		
MRO NSRF	No	The FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an

Organization	Yes or No	Question 1 Comment
		attachment to a standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Additionally, the definition of Frequency Bias Setting should focus on what it is. Balancing Authorities do not supply energy. Suggest revising it to:Frequency Bias Setting A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to approximate the expected natural response provided by the assets within the respective Balancing Authority's area.

Response: The SDT has modified the definitions to no longer reference any other documents.

The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

The SDT agrees that the Balancing Authority does not directly supply energy. However, the NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.

There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.

Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.

The SDT also believes that the definition you have suggested is basically saying the same thing as the definition the SDT has

Organization	Yes or No	Question 1 Comment
chosen to use.		
Alberta Electric System Operator	No	The FRO definition is specific to BAs. The Appendix 1, which is incorporated in the standard, uses this definition in relation to requirements of the Interconnection. The SDT should consider a revision of this definition that accounts for the requirements of the Interconnection versus the BA obligation to the Interconnection.
Response: The definition is referencing the responsible entity, the BA. The Interconnection's FRO is only calculated as the beginning point for the determination of the BA's FRO.		
South Carolina Electric and Gas	No	The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)?
Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to not further modify the definition based on your comments. **The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."**		
SERC OC Standards Review Group	No	We feel that the last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. While the SERC OC Standards Review Group understands the statement, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the

Organization	Yes or No	Question 1 Comment
		definition for Frequency Response Obligation (FRO)?
Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to not further modify the definition based on your comments. **The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."**		
Southern Company	No	We suggest adding BA to the definition of Frequency Response Measure (FRM), similar to the definition for Frequency Response Obligation (FRO).
Response: The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."		
Associated Electric Cooperative Inc	Yes	The FRO definition incorrectly applies the historically narrow Balancing Authority scope of responsibility, while the FRM definition does not address applicability at all. But the BAL-003-1 Standard itself identifies RSGs (where applicable) and BAs as the Responsible Entities within scope of this standard. For consistency, AECI recommends using "Responsible Entities (e.g. Reserve Sharing Groups - where applicable, and Balancing Authorities)" in both the FRO and FRM definitions. Rationale: This change should help future-proof the definition, should more specific "frequency response" or "spinning reserve" sharing groups later surface within our industry. AECI agrees with the Frequency Bias Setting definition's inclusion of a bit more functionality than typical. We however recommend replacing "to account for the Balancing Authority's Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems", with "to support their Frequency Response contribution to the Interconnection". Rationale: Readability, and clarity on

Organization	Yes or No	Question 1 Comment
		the "discouraging withdrawal..." phrase, which should reside in the Background document.
Response: The SDT believes that using the term "Responsible Entities" would cause confusion since different standards could define a Responsible Entity differently. However, the SDT has defined a new term "Frequency Response Sharing Group" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." The SDT has decided not to add the term FRSG to the definition for Frequency Response Obligation (FRO). The SDT believes that the FRO is assigned to a BA not the FRSG. The FRSG FRO is a summation of the BA FRO's. The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to not further modify the definition based on your comments.		
SCE&G	Affirmative	The last phrase of the definition of Frequency Bias Setting is more of an explanation of a function rather than a definition. Therefore, we do not feel it belongs in the definition of the Frequency Bias Setting and a period should be inserted after the word "Interconnection". Should the definition for Frequency Response Measure (FRM) be specific to the BA, similar to the definition for Frequency Response Obligation (FRO)? o The utilization of the term, "Reserve Sharing Group", is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as "Frequency Response Sharing
Response: The SDT thanks you for your suggestion but feels that the statement referenced provides further clarity and has decided to not further modify the definition based on your comments. The SDT has modified the definition for FRM to state that is the responsibility of the BA. The definition now read "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."		

Organization	Yes or No	Question 1 Comment
The SDT agrees that using the phrase Reserve Sharing Group could cause confusion. The SDT has defined a new term "Frequency Response Sharing Group". The definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." The SDT has decided not to add the term FRSG to the definition for Frequency Response Obligation (FRO). The SDT believes that the FRO is assigned to a BA not the FRSG. The FRSG FRO is a summation of the BA FRO's.		
Bonneville Power Administration	Yes	
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
Western Electricity Coordinating Council	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
Florida Power & Light Company	Yes	
FPL	Yes	
FMPP	Yes	

Organization	Yes or No	Question 1 Comment
Xcel Energy	Yes	
Tucson Electric Power	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	
Great River Energy	Yes	

2. **The SDT has made minor modifications to the Requirements R1 through R4 to provide additional clarity. Do you agree that these modifications provide sufficient clarity to comply with the standard? If not, please explain in the comment area.**

Summary Consideration: The majority of the commenters felt that the use of an RSG as a method for supplying Frequency Response was not fully explained. The SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Many of the commenters were concerned with the language in Requirement R3 stating that an entity had to be operating in Tie Line Bias mode unless there were adverse affects on the BES. The SDT removed this requirement from the proposed standard since it is duplicative of Requirement R6 and R7 in BAL-005-0.1b.

Many of the commenters did not agree with assigning the BA to provide Frequency Response. The NERC Functional Model and FERC cited the BA as the responsible party for providing Frequency Response. There are several different methods available to the BA to provide Frequency Response included in the Background Document.

A few of the commenters did not agree with lowering the minimum Frequency Bias Setting. Early research by Nathan Cohn on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

A couple of commenters were concerned that the BA could be responsible to supply an infinite amount of Frequency Response. They felt that a BA could not prepare for this in its planning process. The proposed standard was not clear on this subject and the SDT has added language in the "Event Selection Criteria" section of Attachment A to limit the amount of Frequency Response a BA would be required to provide to be compliant with the standard.

Organization	Yes or No	Question 2 Comment
Seattle City Light	Negative	The language in Requirement 4 needs to be clarified and recommends the following change: R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning]
Response: The SDT has modified Requirement R4 to use bullets in support of your suggestion.		
Public Utility District No. 1 of Douglas County	Negative	1. Recommend clarifying the language in R1 to include background information as to how RSGs fit into the FRM performance. 2. Recommend R3 language be modified to permit operation in other than tie-line bias mode with the requirement to notify the RC. 3. We have concern about the affect R3 will have on the WECC time error correction standard (BAL-004-WECC-1). 4. Clarification is needed between Attachment A and the Background Document for projected peak and historical peak. 5. We have a concern about the affect of lowering the minimum frequency bias obligation from 1% to .8% and its probable affect on reliability. 6. We have a concern about he upper limit to the amount of frequency response expected from BAs.
Response: Comment 1 – The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes		

Organization	Yes or No	Question 2 Comment
that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." Comment 2 & 3– The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b. Comment 4 – The SDT has corrected the error between Attachment A and the Background Document. Comment 5 – Early research by Nathan Cohn[2] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations. Comment 6 – The SDT understands your concern and agrees that this could cause problems with compliance. The SDT has modified Attachment A to include language which puts an upper limit on the amount of Frequency Response required from an entity.		
Potomac Electric Power Co.	Negative	1)The proposed Requirements do not meet all the FERC directives. 2)The proposed Requirements fail to recognize the fact that not all BAs can provide primary frequency response. 3)The proposed Requirements are not all in the standard. Some are in the Attachments.

[2] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
Response: Comment 1 – The SDT disagrees with you about their meeting all of the FERC directives. Unfortunately your comment does not provide specific information as to what you believe is not being addressed. The SDT has included a section within the Background Document which details how this standard is meeting the FERC directives. **Comment 2 – The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.** **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **Comment 3 – Unfortunately your comment does not provide enough information as to what parts of the attachments you believe should be in the requirements. However, the SDT has made significant modifications to both Attachment A and Attachment B now a Procedure for the ERO to follow in support of the proposed standard. The SDT believes that the requirements should be succinct and the methodologies to be used should be part of an attachment.**		
Seattle City Light	No	o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority's Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:- Telemetry problems that lead the operator to believe ACE is significantly in error.-

Organization	Yes or No	Question 2 Comment
		The frequency input to AGC is not reflective of the BA's true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems. o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change (in red):R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) calculate the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning] o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of "natural frequency response" as a third bullet item to Requirement 5 (in red). The revised requirement would read: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment

Organization	Yes or No	Question 2 Comment
		B. o The natural frequency response
Response: The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b. **The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.** **The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.**		
FMPP	No	o R1. Each Balancing Authority (BA) or Reserve Sharing Group (RSG) shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency Response in the Interconnection. [Risk Factor: Medium][Time Horizon: Operations Assessment] The BA does not have control over the frequency responsive generation. There needs to be a requirement that the GOP shall set frequency response for the generators as directed by the BA. o R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is {greater than or (<= add these words)} {at least (<= delete these words)} equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B.

Organization	Yes or No	Question 2 Comment
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **With regards to your comment concerning Requirement R5, you have not provided enough information for the SDT to respond. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.**		
Western Electricity Coordinating Council	No	Agree with the changes made to this latest version of BAL-003-1. However, additional clarity could be added by addressing the following: R1- It is not clear what is intended by "Reserve Sharing Group". As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R3 - There may be occasions in which an entity has a legitimate reason or a need to operate in a mode other than Tie Line Bias but that does not qualify as an Adverse Reliability Impact. Recommend including language that would permit limited operation in a mode other than Tie Line Bias mode provided the Reliability Coordinator was notified. R3 - Has the drafting team considered whether or not the

Organization	Yes or No	Question 2 Comment
		language of Requirement R3 will have any conflict or coordination issue with the FERC-approved regional reliability standards BAL-004-WECC-1 - Automatic Time Error Correction? R5 - Suggest changing the language “at least equal to” to “greater than or equal to” for clarity.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.” **The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.** **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.**		
Seattle City Light	Negative	Answer: No Comments: o LADWP and SCL have a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias mode and not have an Adverse Reliability Impact on the Balancing Authority’s Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances: - Telemetry problems that lead the operator to believe ACE is significantly in error. - The frequency input to AGC is not reflective of the BA’s true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection). - During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them). - For training purposes. - Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems.

Organization	Yes or No	Question 2 Comment
		o LADWP and SCL believe that the language in Requirement 4 needs to be clarified and recommends the following change: R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning] o LADWP and SCL believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. SCL recommends the addition of "natural frequency response" as a third bullet item to Requirement 5. The revised requirement would read: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The natural frequency response

Response: The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.

The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.

The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement

Organization	Yes or No	Question 2 Comment
R2 and a new Requirement R3.		
Avista Corp.	Negative	As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly including an example in the background document to help explain how this would work. Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." Early research by Nathan Cohn[3] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting		

[3] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.		
City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc., Clark Public Utilities, Avista, Tri-State G & T Association, Inc.; Deseret Power	Negative	As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term “Frequency Response Sharing Group (FRSG)” because it believes that using the presently defined term “Reserve Sharing Group” could cause confusion. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.”		
Sacramento Municipal Utility District (SMUD)	No	As drafted, requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifying this concept and possibly including an example in the background document to help explain how this would work. As drafted, in requirement R3, each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority’s Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or

Organization	Yes or No	Question 2 Comment
		desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.**		
Energy Mark, Inc.	No	Comment 1: The timing requirements for implementing the Frequency Bias Setting are not specified for BAs participating in Overlap Regulation Service. The requirements indicate the value that should be used for the Frequency Bias Setting, but they do not indicate when those settings should be implemented. Comment 2: The term "Tie Line Bias mode" in Requirement R3 is not sufficiently defined to make this requirement enforceable. Any operating mode labeled as "Tie Line Bias mode" on an EMS that uses interchange scheduled and frequency error as inputs will meet the standard requirement as stated. This loop-hole exists because the NERC definition of "Tie Line Bias" fails to define the term in enough detail to actually limit AGC operation to the specified mode of operation. One way to improve this requirement would be to redefine Tie Line Bias in the NERC Glossary as a mode that uses the NERC ACE Equation as defined in BAL-001 as the basis for AGC action when the EMS is in Tie Line Bias mode. Comment 3: The standard is silent on how a BA receiving Overlap Regulation Service should set its Frequency Bias Setting. Unless this is explicitly stated, it will be up to

Organization	Yes or No	Question 2 Comment
		the auditors to determine the value of the Frequency Bias Setting for BAs receiving Overlap Regulation Service. Comment 4: In general, the requirements indicate what the responsible BAs should do and when. The requirements do not indicate what the BAs that are not responsible should do and when, ie. how they are relieved from responsibility. This may create problems when the auditors are required to interpret the standards for BAs that have appropriately shifted responsibilites to others.
Response: Comment 1 – The SDT believes that Requirement R2 states the timing for implementation of the Frequency Bias Setting. The Requirement R4 is simply to provide the BA with the method for combining the Frequency Bias Settings for providers of Overlap Regulation Service. The Background Document and Attachment A have also been modified to provide further clarity. **Comment 2 – The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.** **Comment 3 & 4 – The SDT does not believe that there is an issue for entities receiving Overlap Regulation Service. However, the SDT has modified the Background document to further clarify this issue.**		
Duke Energy	No	Duke Energy supports the concept of a group of BAs forming a group to share in Frequency Response however it should be clear that it is an option. We feel that the utilization of the term, “Reserve Sharing Group”, is not consistent with the definition in the NERC Glossary of Terms which is specific to sharing of contingency reserves, and should be replaced with a new term, such as “Frequency Response Sharing Group”. R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in “Tie Line Bias” mode. Though comments are provided below on the Attachments, Duke Energy believes that all NERC Reliability Standards’ requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval), and not within Attachments that may be revised without Industry review and approval. As noted below and in prior comments, given the secondary control implications of changing

Organization	Yes or No	Question 2 Comment
		the minimum Frequency Bias Setting (FBS), Duke Energy believes that subsequent revisions to the minimum FBS should be vetted through the Standards process. Duke Energy would suggest moving the details of the minimum FBS for each Interconnection into the Standard, and having the implementation plan include annual submittal of a revised minimum FBS based upon the methodology presented in Attachment B for ballot approval by the Industry.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it also believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **The SDT has removed the Requirement R3 from this version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b.** **Attachments that are referenced within a Requirement are mandatory and enforceable.** **Early research by Nathan Cohn[4] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.** **The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.**		
ISO/RTO Council Standards Review Committee	No	General CommentsThe SRC offers the following general comment with regard to the SDT's proposed revisions: Gerry Cauley's Results based initiative calls for

[4] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 2 Comment
		requirements that focus on performance (i.e. WHAT must be accomplished NOT on WHY it is required or HOW it should be accomplished). The SRC has found that such explanatory statements as the SDT is proposing lead to ambiguities and confusion in the compliance application. Compliance Enforcement agents must consider not just the results but must decide if the action was taken for the given reason. To avoid such confusion, the Results based approach uses reference documents to address such background material while leaving the requirement as a direct mandate.The SRC notes: o All NERC Reliability Standards' requirements must reside within the standard itself (which is vetted by the Industry and subject to FERC approval). o Data requirements are better handled through NERC's Rules of Procedure Section 1600 than by mandating that ad hoc Forms be submitted. o Definitions should be generic, and should be self-contained (i.e. should not reference an external document). o The decisions regarding alternative methodologies should be decided by the Industry not by the SDT. The SDT should make its case and ask the Industry for its approval. Regarding Order 693 directives, the SRC notes that there are three directives as follows: (1) To include Levels of Non-Compliance; (2) To determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) To define the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.

Organization	Yes or No	Question 2 Comment
		The SRC suggests that Directive 2 be handled directly as a mandate that the ERO conduct a fixed number of Frequency Response Surveys for randomly selected events. Discussion of the number and the methodology can be explained in a reference document and leave the specifics to the requirement. Directive 3 is critical to the Industry as it relates to who is the Applicable Entity. The SDT addresses Directive 3 by mandating Balancing Authorities meet an objective. The directive is to define that Objective, but there is no requirement associated with that Objective. There is an attachment and there are discussions of what "may" be done, but there is no requirement in the Standard itself. The reference to the BA as the provider of Frequency Response (i.e. Primary Control response) runs counter to other FERC directives that mandate obligated entities be able to self-serve or to interchange provision of services. In this case the BA per se has no assets and cannot self-serve, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a federally mandated standard to comply with. The idea of creating a Primary Response Market as some have proposed does not work without an obligation on some entity to physically provide that service. One final note, the SRC points out that the ACE is an error signal used to drive secondary response; it is not a signal to drive primary response. Thus the use of the Frequency Bias setting is not for control, it is for "adjusting" the error measure that is analyzed after the fact.This standard needs: o a requirement on the ERO to compute the Obligation on each Interconnection o a requirement on the ERO to conduct Frequency Response surveys (note the SRC does not support this requirement but believes that it is needed to meet the FERC directive) o a requirement on energy supply assets (both generation and load) to provide primary response (as a function of the Interconnection obligation in the first bullet)

Organization	Yes or No	Question 2 Comment
		The above will allow NERC to comply with the FERC directives in a fashion consistent with the processes and procedures approved by FERC. Specific recommendations: The SRC proposes that R1 be deleted based on the facts that: o It imposes an obligation on an entity that has no capability to comply o There is an internal conflict with imposing penalties on a deterministic basis (compliance with a fixed set of events) for a statistical service (primary response is a function of the assets operating state and not a fixed service of the asset).In any case, all of the words after FRO should be deleted. The words are not needed for the requirement and if left in can become a source of contention between auditors and registered entities. R3 - delete the added phrase “mode to effectively coordinate control”.The phrase “would have an Adverse Impact on the BA’s area” needs further discussion. Who makes the decision that operating on AGC will have adverse impact must be defined. R5 - delete the phrase “In order to ensure control response”. Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get “adequate response” then is the BA non-compliant? What is “adequate response”? Who decides if the response is adequate?

Response: Unfortunately your comment does not provide enough information as to what parts of the attachments you believe should be in the requirements. However, the SDT has made significant modifications to both Attachment A and Attachment B, now a Procedure for the ERO to follow in supporting the standard. The SDT believes that the requirements should be succinct and the methodologies to be used should be part of an attachment.

The SDT is using defined forms to ensure that everyone calculates their Frequency Bias Setting and Frequency Response Measure in a consistent manner. The SDT also believes that this provides entities a relatively non-time consuming method to provide the necessary information to evaluate compliance.

Organization	Yes or No	Question 2 Comment
The SDT has modified the definitions to no longer reference any other documents. The SDT is recommending a certain approach to calculating the FRM. The reference to other methods being evaluated is simply a statement that the SDT believes that further analysis would be beneficial. Any modification to the calculation methodology would require industry approval. The SDT believes that it is meeting Directive #2 by requiring at least 20 events to be analyzed each year. The SDT believes that it is meeting the directive to define the "objective" by creating the BA Frequency Response Obligation (FRO). With regards to the BA being the responsible entity to provide Frequency Response the NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost. Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect. The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration. The ERO is not defined as an applicable entity in the industry approved SAR and therefore it would be inappropriate to include them as an applicable entity.		
Los Angeles Department of Water and Power	No	LADWP has a concern with Requirement 3. The requirement should provide allowance for legitimate circumstances when an entity cannot run on Tie Line Bias

Organization	Yes or No	Question 2 Comment
		mode and not have an Adverse Reliability Impact on the Balancing Authority's Area. An entity should not be penalized when these legitimate circumstances occur. LADWP believes that the Frequency Response Standard Background Document, on Page 8, lists examples of legitimate circumstances:- Telemetry problems that lead the operator to believe ACE is significantly in error.- The frequency input to AGC is not reflective of the BA's true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection).- During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them).- For training purposes.- Many AGC systems will automatically switch to an alternate mode if the EMS determines Tie Line Bias control could lead to problems. LADWP believes that the language in Requirement 4 needs to be clarified and recommends the following change:- R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation to be equivalent to either (i) the sum of the Frequency Bias Settings of the participating Balancing Authorities as validated by the ERO, or (ii) the Frequency Bias Setting as calculated based on the entire area being combined and thereby represent the Frequency Response for the combined area being controlled. [Risk Factor: Medium][Time Horizon: Operations Planning] LADWP believes the language in Requirement 5 needs to be modified to be consistent with that of the second paragraph of Attachment B. LADWP recommends the addition of "natural frequency response" as a third bullet item to Requirement 5. The revised requirement would read:- R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is at least equal to one of the following: [Risk Factor: Medium][Time Horizon: Operations Planning] o The minimum percentage of the Balancing Authority Area's estimated yearly Peak Demand within its metered boundary per 0.1 Hz change as specified by the ERO in accordance with Attachment B. o The minimum percentage of the Balancing Authority Area's estimated yearly peak generation for a generation-only Balancing Authority, per 0.1 Hz change as

Organization	Yes or No	Question 2 Comment
		specified by the ERO in accordance with Attachment B. o The natural frequency response
Response: The SDT has removed the Requirement R3 from the next version of the proposed standard. This removal was based on industry comments and the belief that it was duplicative with Requirements R6 and R7 in BAL-005-0.1b. **The SDT has modified Requirement R4 which now uses bullets in support of your suggestion.** **The SDT disagrees with your suggested modification. The SDT believes that your suggested modification could allow for an entity to circumvent the minimum percentage process. However, the SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.**		
MidAmerican Energy Co.	Negative	MidAmerican supports the comments provided by the NSRF. It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. It is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.5). Without a statement that the BA is expected to keep its allocated portion of generation reserves only up to the largest event identified in Table 2, a BA could be expected to provide limitless amounts of frequency response. Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately.
Response: The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.		
East Kentucky Power Coop.; ACES Power Marketing; Hoosier Energy Rural Electric Cooperative, Inc.; Southwest Transmission Cooperative, Inc.	Negative	Overall, [we] believes the drafting team has done an excellent job to address the FERC directives from Order 693. However, we believe there is still room for improving the standard and that there is a significant technical error. The technical error was introduced by applying Requirement 1 to the RSG and is discussed below. Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups (RSG) are designed to share Contingency Reserves and/or Operating Reserves not

Organization	Yes or No	Question 2 Comment
		Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation. Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the "Frequency Response Standard Background Document". While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding. In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected. Furthermore, the document should clarify if the Contingency Protection Criteria contains the "safety margin". There is a statement in the paragraph before the table that states it does, but then the table lists out a separate 25% "Safety Margin". Thus, it is not clear if the "Safety Margin" is included in the Contingency Protection Criteria value listed in the table or not. "Safety margin" should be changed to "reliability margin". Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin. The Data Retention section requires the BA to retain data or evidence for up to four years. No data that exceeds the audit cycle should be required to be retained. The audit cycle is three years for BAs.
Response: The SDT agrees that using the term "Reserve Sharing Group" could cause confusion and has defined a new term "Frequency Response Sharing Group (FRSG)". The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency		

Organization	Yes or No	Question 2 Comment
Response Obligations of its members.” The SDT agrees with your comment concerning further clarification on certain terms and has made significant modifications to the Background Document and Attachments A and B. The Data Retention is stated as “the current year plus three calendar years” since it is highly unlikely that an entity will be audited exactly three years after its previous audit. The SDT recognizes that most audits will occur within the year following the third year.		
PPL Electric Utilities Corp.; PPL Generation LLC	Negative	The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed standard.
Response: The SDT disagrees that an RSG is not an appropriate mechanism for providing Frequency Response. However the SDT does believe that using the term “Reserve Sharing Group” could cause confusion and has defined a new term “Frequency Response Sharing Group (FRSG)”. The new definition reads “A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.” Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a		

Organization	Yes or No	Question 2 Comment
means to meet one of the FERC's Order No. 693 directives. **FRSG performance may be calculated on one of two ways:** • **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or** • **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**		
Progress Energy	No	PGN supports the collective comments of SERC members.We feel that the utilization of the term, "Reserve Sharing Group", is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as "Frequency Response Sharing". R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in "Tie Line Bias" mode
Response: The SDT agrees that using the term "Reserve Sharing Group" could cause confusion and has defined a new term "Frequency Response Sharing Group (FRSG)". The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.**		
MRO NSRF	No	R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R2 - Please add the word "range" in-between the words "date" and "specified". The background document specifies that there is a 72-hour period to implement the FBS setting (See Background document Page 7). R2, as written, does not reflect the

Organization	Yes or No	Question 2 Comment
		period for which an entity may implement the ERO validated Bias into ACE. Also see our comment on #7 as to the length of the comment period. Question 7 comment is provided to assist the SDT; Note from question 7: (Page 7 (3rd paragraph) of the Background document states "Given the fact that BA's can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date. 1. The Standard itself does not state this provision (24 hour window on each side of target date) as indicated. 2. The SDT accurately addresses the fact that BA's could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.) R3 - Recommend the term "Adverse Reliability Impact" be removed from Requirement 3. Based on the NERC definition of the term, a smaller entity could never operate its AGC outside of TLB mode due to their impact on the BES not likely to result in "instability or Cascading". To ensure a more consistent and equitable approach when applying this Requirement, recommend the drafting team incorporate the reliability reasons listed within the Background Document into the actual Requirement. Additionally, the phrase "effectively coordinated control" should be removed as this is not essential to the Requirement and introduces ambiguity in its application. To this end, the following revisions are proposed: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode to ensure effectively coordinated control, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area meets one or more of the following conditions.

Organization	Yes or No	Question 2 Comment
		o Telemetry problems that lead the operator to believe ACE is significantly in error. o The frequency input to AGC is not reflective of the BA's true frequency (such as if the control center were operating a local generator and disconnected from the Interconnection). o During restoration (where one BA might be controlling frequency while another to which it is connected is managing interchange between them). o For training purposes. o Many AGC systems will automatically switch to an alternative mode if the EMS determines Tie Line Bias control could lead to problems. o For single BA Interconnections, Flat Frequency and Tie Line Bias are equivalent. o The Reliability Coordinator has been informed and the duration is [insert time constraint language here]. R5 - Recommend to delete the phrase "In order to ensure control response". Such phrases can be needless causes of debate. If a BA uses one of the bulleted methods but does not get "adequate response" then is the BA non-compliant? What is "adequate response"? Who decides if the response is adequate? Please clarify.

Response: The SDT agrees that using the term "Reserve Sharing Group" could cause confusion and has defined a new term "Frequency Response Sharing Group (FRSG). The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**

Organization	Yes or No	Question 2 Comment
• **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.** **The SDT has modified Requirement R2 to provide better clarity. The requirement now reads "**Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO to ensure effectively coordinated Tie Line Bias control.**".** **The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.** **The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.**		
Xcel Energy	No	R1- It is not clear what is intended by "Reserve Sharing Group" in this context. As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly include an example in the background document to help explain how this would work. R3 - recommend modifying the language to permit AGC out of TLB mode if the RC is notified; also remove the "to ensure coordinated control" as this is not essential for the requirement. Our reasoning behind the suggested change to notification of the RC is that there are occassions where an entity would need to perform testing, etc and it could be argued that testing would not be sufficient justification for meeting the Adverse Reliability Impact definition. Here is proposed revised language:Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless the Balancing Authority's Reliability Coordinator has been informed and the duration is [insert time constraint language here].
Response: The SDT agrees that using the term "Reserve Sharing Group" could cause confusion and has defined a new term "Frequency Response Sharing Group (FRSG)". The new definition reads "A group whose members consist of two or more		

Organization	Yes or No	Question 2 Comment
Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.**		
Constellation Energy Commodities Group	No	R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below: R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority's FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs.- In R2, "Each Balancing Authority not participating in Overlap Regulation Service" should state "Each Balancing Authority, not receiving Overlap Regulation, shall implement the appropriate Frequency Bias Setting (fixed or variable,) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control". – In R3, the explanatory language about why to operate in Tie Line Bias mode should be deleted. See proposed modification below: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area.- R5 should be modified to state only that the FBS is specified by the ERO in accordance with Attachment B. As drafted the Requirement is in conflict with Attachment B because the Requirement mandates a minimum and does not allow for a reduction to the minimum but it references Attachment B which is titled

Organization	Yes or No	Question 2 Comment
		"Process for Adjusting Minimum Frequency Bias Setting". See proposed modification below: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is as specified by the ERO in accordance with Attachment B.- There should be a Requirement specifically stating there is an obligation to complete and submit FRS Form 1 by January 10th each year for clarity.- The requirements should be re-ordered to reflect the chronology of the process for frequency calculation, implementation and performance measurement. The recommended order is as follows: R5 which defines the minimum Frequency Bias Setting (FBS) for a Balancing Authority R4 which describes how the minimum FBS may be altered through Overlap Regulation Service R2 which identifies the coordination required around implementationR3 which requires operation in Tie Line Bias mode R1 which establishes the performance obligation
Response: The SDT does not see anything within the Requirement that would restrict any agreements between multiple BAs and RSGs. However, the SDT has modified the language in Requirement R1 to provide additional clarity. The requirement now reads "Each Balancing Authority or Frequency Response Sharing Group (FRSG) shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each Balancing Authority or FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." The SDT has also defined a new term "Frequency Response Sharing Group (FRSG)" because it also believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to		

Organization	Yes or No	Question 2 Comment
jointly meet the Frequency Response Obligations of its members." **The SDT has modified Requirement R2 to provide better clarity. The requirement now reads "**Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO to ensure effectively coordinated Tie Line Bias control.**".** **The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.** **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT also believes that Attachment B, now a Procedure for the ERO to follow in supporting the standard, only details the process the ERO is to use when evaluating and making modifications to the minimum Frequency Bias Setting.** **The SDT disagrees with your comment concerning an additional requirement for timing of reporting. The SDT believes that this is an administrative issue and is better handled within an attachment. The SDT would also like to note that an attachment when referenced in a requirement becomes mandatory and enforceable.** **The SDT thanks you for your suggested ordering for the requirements but believes that the revised proposed standard reflects the proper order in that it sets the goal at beginning of year, calculates performance, reports performance and calculates bias at the end of the year.**		
Constellation Energy	Negative	-R1 should accommodate agreements between multiple BAs and RSGs in achieving the annual Frequency Response Measure. See proposed modification below: R1. Each Balancing Authority shall achieve an annual Frequency Response Measure (FRM) (as detailed in Attachment A and calculated on FRS Form 1) that is equal to or more negative than its Frequency Response Obligations (FRO) to ensure that sufficient Frequency Response is provided by each BA. Either the Balancing Authority individual FRM, multiple Balancing Authority's FRM per written agreement, or the FRM of the Reserve Sharing Group must be equal to or more negative than the applicable Frequency Response Obligations (FRO) for a single Balancing Authority or the aggregate of multiple Balancing Authorities or RSGs. -In R2, "Each Balancing Authority not participating in Overlap Regulation Service"

Organization	Yes or No	Question 2 Comment
		should state "Each Balancing Authority, not receiving Overlap Regulation, shall implement the appropriate Frequency Bias Setting (fixed or variable,) validated by the ERO, into its Area Control Error (ACE) calculation beginning on the date specified by the ERO to ensure effectively coordinated Tie Line Bias control". -In R3, the explanatory language about why to operate in Tie Line Bias mode should be deleted. See proposed modification below: R3. Each Balancing Authority not receiving Overlap Regulation Service shall operate its Automatic Generation Control (AGC) in Tie Line Bias mode, unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. -R5 should be modified to state only that the FBS is specified by the ERO in accordance with Attachment B. As drafted the Requirement is in conflict with Attachment B because the Requirement mandates a minimum and does not allow for a reduction to the minimum but it references Attachment B which is titled "Process for Adjusting Minimum Frequency Bias Setting". See proposed modification below: R5. In order to ensure adequate control response, each Balancing Authority shall use a monthly average Frequency Bias Setting whose absolute value is as specified by the ERO in accordance with Attachment B. -There should be a Requirement specifically stating there is an obligation to complete and submit FRS Form 1 by January 10th each year for clarity. -The requirements should be re-ordered to reflect the chronology of the process for frequency calculation, implementation and performance measurement. The recommended order is as follows: R5 which defines the minimum Frequency Bias Setting (FBS) for a Balancing Authority R4 which describes how the minimum FBS may be altered through Overlap Regulation Service R2 which identifies the coordination required around implementation R3 which requires operation in Tie Line Bias mode R1 which establishes the performance obligation

Response: The SDT does not see anything within the Requirement that would restrict any agreements between multiple BAs and RSGs. However, the SDT has modified the language in Requirement R1 to provide additional clarity. The requirement now reads

Organization	Yes or No	Question 2 Comment
"Each Balancing Authority or Frequency Response Sharing Group (FRSG) shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each Balancing Authority or FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." The SDT has also defined a new term "Frequency Response Sharing Group (FRSG)" because they also believed that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **The SDT has modified Requirement R2 to provide better clarity. The requirement now reads "**Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO to ensure effectively coordinated Tie Line Bias control.**".** **The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.** **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT also believes that Attachment A only details the process the ERO is to use when evaluating and making modifications to the minimum Frequency Bias Setting.** **The SDT disagrees with your comment concerning an additional requirement for timing of reporting. The SDT believes that this is an administrative issue and is better handled within an attachment. The SDT would also like to note that an attachment when referenced in a requirement becomes mandatory and enforceable.** **The SDT thanks you for your suggested ordering for the requirements but believes that the revised proposed standard reflects the proper order in that it sets the goal at beginning of year, calculates performance, reports performance and calculates bias at the end of the year.**		
Ameren	No	R1.While we agree with the concept of the entire requirement and the determination of the Interconnection Frequency Response Obligation, we believe that the accurate measurement of individual BA's FRM has not yet been demonstrated. This requirement should not be part of the standard (even with the additional 12 months in the effective date) until the field trial demonstrates that

Organization	Yes or No	Question 2 Comment
		each BA's FRM can be consistently calculated to a level that will not create false non-compliance to this requirement. While the calculation methodology in FRS Form 1 looks promising, with the A-value and B-value average periods, we believe successful completion of the field trial is prudent. R5. We were not sure if it was intended for this comment question to include Requirement R5, but have decided to include our comments here. While we agree with the requirement of R5, it should not be at the expense of changing the value of L10 in BAL-001, R2, which has been accepted by FERC in Order 693. An accommodation should be made so that any changes to the Frequency Bias Setting according to BAL-003, R5, should not affect the value of L10 used in BAL-001, R2.
Response: The SDT agrees that validation of the methodology needs to occur. However, the SDT is working under a FERC approved deadline for completion of this project. The SDT is recommending that continued analysis should occur during the filing period and implementation period of the standard. The STD has also added considerable language to the Background Document on why it has chosen the methodology it is recommending for this standard. **The SDT understands your concern with the reduction of the minimum Frequency Bias Setting affecting other performance standards. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a “go slow” approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.**		
American Electric Power	No	R1: Clarification is needed regarding the responsibility of a BA that is a member of a Reserve Sharing Group. R2 and R3: What does “coordinated control” mean? There no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some performance measures.

Organization	Yes or No	Question 2 Comment
		This revision adds new performance measure responsibilities on the BA who likely has no direct control over every resource affecting their performance within their footprint. We are not necessarily challenging the performance measures themselves, nor their underlying objectives, however AEP views this as a gap in responsibilities which potentially effects reliability.

Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" to eliminate any confusion with the present d3efined term "Reserve Sharing Group". The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**
- **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**

The SDT has been instructed to include a "reliability outcome" within the requirements and therefore included the language "…coordinated control…". The SDT understands that this does not provide any additional clarity for complying with the requirement and could be removed. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.

The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.

The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

Organization	Yes or No	Question 2 Comment
The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost. Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.		
Great River Energy	No	R1: Including the Reserve Sharing Group (RSG) in the Frequency Response Obligation is outside of the boundaries of a RSG. Where or how would a Frequency Bias be determined for an RSG to determine their Frequency Response Obligation? Although it is apparent that frequency responds during the implementation of reserves, the intention of a RSG is not to share frequency response, but rather to share Reserves. Additionally, if the Frequency Response Obligation is not met by the RSG how are penalties assessed? Should they be assessed to the group as a whole or strictly to the generators that did not meet their individual obligation? R3: Needs to include verbiage for those circumstances when it would be necessary to run AGC out of TLB such as during necessary testing. The BA should have the option to operate out of TLB for a predetermined amount of time if needed when notification and coordination with the RC has been established.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine		

Organization	Yes or No	Question 2 Comment
how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives. **FRSG performance may be calculated on one of two ways:** • **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or** • **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.** **The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.** **The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.**		
Tucson Electric Power	No	R1: TEP feels that the FRO should be able to be calculated by the BA and that Form 1 changes should be treated via the Standard drafting process. R2: TEP feels that use Form 1 should be required by the Standard. Further, BAs should calculate its own frequency bias setting without ERO intervention. R3: Operating outside Tie Line Bias mode should be allowed during a year to allow for the testing of other modes. R4: Agree with the concept, but without ERO intervention. R5: Should read "greater than or equal to".
Response: The FRO can be estimated by the BA but the actual BA FRO for compliance is based on the BA's footprint and is a function of the Interconnection FRO. Modifications to the FRS Form 1 would go through the Standard Drafting Process. **R3 - The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.** **R2 and R4 - The Frequency Bias Setting is calculated on FRS Form 1. The ERO is only validating the data used in the calculation. This is a practice that exists today. History has shown that there typically are errors in the data.** **R5 - The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has**		

Organization	Yes or No	Question 2 Comment
modified the requirement and believes we have implemented the intent of your suggestion.		
SCE&G	Affirmative	R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in "Tie Line Bias" mode. o We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1 o
Response: The requirement to operate AGC in Tie Line Bias mode has been removed from the standard since it was duplicative of Requirements R6 and R7 in BAL-005-0.1b. **The SDT has modified Attachment B, now a Procedure for the ERO to follow in supporting the standard, to address your concern. The new title is, "Frequency Bias Setting Minimums".**		
Bonneville Power Administration	No	Regarding R1, BPA believes that adding additional requirements in R1 by referencing Attachment A does not add clarity. FRO should be a calculation that the BA's can do themselves and included within the standard. Can Form 1 be changed outside of the standard drafting process? BPA doesn't believe that Form 1 should be allowed to be changed outside of the standard drafting process. As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. BPA recommends clarifying this concept and possibly including an example in the background document to help explain how this would work. Regarding R2, BPA believes each BA should be able to calculate its own frequency bias setting without ERO validation. The standard can require the BA to use Form 1, if the BA doesn't use Form 1 correctly, then the BA would be in violation of the

Organization	Yes or No	Question 2 Comment
		standard. BPA believes that R3 should include a minimal amount of time (suggesting a couple of hours per year) to allow for testing other modes. Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. BPA recommends including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.BPA seeks clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction. BPA agrees with the concept of R4, however, BPA again disagrees with the ERO validation of the frequency bias setting. BPA believes that reducing frequency bias obligation is detrimental to reliability. It seems that lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. BPA believes that over time, it would seem that this pattern would lead to poorer response. BPA believes that R5 should read "greater than or equal to one of the following" not " at least equal to". The requirement should be a part of Form 1 or included in R2. For variable bias, the minimum percentage should be based on the forecasted month peak.

Response: R1 – The FRO can be estimated by the BA but the actual BA FRO for compliance is based on the BA's footprint and is a function of the Interconnection FRO.

Organization	Yes or No	Question 2 Comment

Modifications the FRS Form 1 would go through the Standard Drafting Process.

The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.

The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.

R2 – The SDT is interested in the use of good data for the calculations but does not believe that a BA should be penalized for minor data errors. This is why the SDT proposes that the ERO validate the data. In addition, this process is used today.

R3 - The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.

R4 – Again, this is a process that is in use today. The SDT is not proposing that the ERO modify anything, just proposing that the ERO validate the data being supplied.

R5 - The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. However, the SDT understands your concern with the reduction of the minimum Frequency Bias Setting affecting other performance requirements. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change

Organization	Yes or No	Question 2 Comment
in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.		
Manitoba Hydro	No	Regarding R1: 1. Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an RSG to comply versus a BA. In particular (i) At p.3, Attachment A states that the ERO is responsible for “annually assigning an FRO and Frequency Bias Setting to each BA.” No mention is made of RSGs. (ii) Attachment A only references RSGs in the context of reporting obligations for Form 1 (at p.4) and (iii) Compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an RSG and that in such cases the RSG has the same responsibilities as each BA (that is a participant in the RSG). 2. It should be clarified that this requirement applies to a BA, where the BA doesn’t belong to an RSG, OR to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply. Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation. 3. R1 does not specify where or how the FRO is determined. Presumably this would be determined by the ERO pursuant to Attachment A. 4. The phrase “to ensure that sufficient Frequency Response ...” should be separated from the requirement as it is

Organization	Yes or No	Question 2 Comment
		(i) not descriptive of the required actions; (ii) redundant with the stated purpose at the beginning of the standard. In general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met. Regarding R2: 1. It is not clear from R2 who determines the Frequency Bias Setting for "validation" by the ERO and how the FBS is determined. (Presumably done by the BA in accordance with Attachment B). Based on Background document, should refer to those "published" by ERO. The BA's FBS may not be validated, and may be modified before posting. 2. Attachment B does not refer to the ERO "validating" FBS. 3. Attachment B refers to an RSG calculating FBS, but the standard does not.

Response: R1 – Comment 1 & 2 – The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**
- **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual**

Organization	Yes or No	Question 2 Comment
performance. The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. Comment 3 – The process for determining the FRO is detailed in Attachment A. Comment 4 – The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration. R2 – Comment 1 – The Frequency Bias Setting is calculated on FRS Form 1. The ERO is only validating the data not calculating the setting. The ERO will be working with the BA to correct any data errors discovered during the validation process. This is a process that is in use today Comment 2 & 3 – The SDT has made significant modifications to the Background Document and Attachment A to provide additional clarity. The SDT has added language to Attachment A regarding validation of the BA data. The SDT has removed all references to a FRSG for Frequency Bias Setting. Attachment B has been removed and the information from Attachment B has been incorporated in a Procedure developed by the SDT for the ERO to follow to support this standard.		
NV Energy	No	Requirement 1 seems to be the only one that has any applicability to an RSG; however, it is unclear under what circumstances this requirement applies to an RSG. Suggest changing the R1 to be addressed solely to BA's or alternatively, explain under Applicability section 1.2 what "where applicable" means.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.		

Organization	Yes or No	Question 2 Comment
FRSG performance may be calculated on one of two ways: • **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or** • **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.** **The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.**		
ACES Power Marketing Standards Collaborators	No	Requirement 1 should not apply to a Reserve Sharing Group. Reserve Sharing Groups (RSG) are designed to share Contingency Reserves and/or Operating Reserves not Frequency Response. While these reserves may be frequency responsive, they are not being shared for the purpose of expanding frequency response. Furthermore, while reserve sharing groups may calculate a joint ACE by summing its individual BA ACE values, RSGs do not have a Frequency Bias Setting which is necessary to assess a Frequency Response Obligation.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." **Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.** **FRSG performance may be calculated on one of two ways:** • **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or** • **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**		

Organization	Yes or No	Question 2 Comment
The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.		
City of Redding, Oregon Public Utility Commission, BrightSource Energy, Inc., Clark Public Utilities, Avista, Tri-State G & T Association, Inc.; Deseret Power	Negative	Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified.
Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.		
Alberta Electric System Operator	No	The language used in the requirements is superfluous. This could result in confusion and incorrect assumptions being made. In R1, the comment within brackets "(as detailed in Attachment A and calculated on FRS Form 1)", is not necessary as it is already part of the FRM definition. We suggest removing this bracketed text from the requirement. Also in R1, the phrase "to ensure that sufficient Frequency Response is provided by each BA or RSG to maintain an adequate level of Frequency response in the Interconnection" is a high level objective that does not add clarity to this requirement. We suggest removing this from the requirement. R2, R3 and R5 use similar language e.g. "to ensure effectively coordinated Tie Line Bias control", "to ensure adequate control response" etc. Although it provides background information, this does not add clarity to the requirement. We suggest removing these from the requirements.
Response: Based on industry comments the SDT has modified the definition for FRM such that it no longer references any other documents. Therefore, the SDT believes that leaving the reference to Attachment in the standard is prudent, based on advice		

Organization	Yes or No	Question 2 Comment
from the standards staff – without a reference to the specific Attachment, the responsible entity can't be held to compliance with the performance identified in that attachment. **The SDT has been instructed to include a "reliability outcome" within the requirements and therefore included the language you are referencing. The SDT understands that this does not provide any additional clarity for complying with the requirement and could be removed. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.**		
Hydro-Quebec TransEnergie	No	The objective of R2 is that all BA's implement their new Bias Setting at the same time, based on the previous year's data, so that control stays the most effective throughout the Interconnection (Tie-Line Bias). In addition, the new Bias will be in effect all year long. The process is quite simple and straightforward for a fixed Bias Setting. As for Variable Bias Setting, this process is not applicable before the fact since the Bias equation can depend on real-time values that are not known in advance. In addition, the simultaneous Bias implementation is not an issue for a single BA Interconnection. Therefore, we suggest that Requirement 2 applies only to Fixed Bias Setting.
Response: The SDT agrees with your comment and has modified Requirement R2 to reflect your concern. The SDT has also added an addition Requirement R3 to address entities using a variable Frequency Bias Setting.		
Northeast Power Coordinating Council	No	The requirements should not be directed at Balancing Authorities, as generators are the main supplier of "discretionary" frequency response. Requirement R1 refers to an attached form, which is not part of the standard and therefore not enforceable.
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.**		

Organization	Yes or No	Question 2 Comment
There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost. **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **If an attachment is referenced in a requirement that attachment becomes part of the requirement. The requirement has been modified to no longer reference an attached form.**		
Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.	Negative	The standard is silent on the "methods to obtain Frequency Response". For instance, the BA does not have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs may not have the authority to achieve. R1 includes the Reserve Sharing Group in its applicability, but none of the other requirements do. There is no consideration of "footprint" changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no allowance for mid-year changes and associated allocation changes. If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn't there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a "user, owner or operator" of the BPS under Section 215, e.g., at (b)(1)"... All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section." I question how this would work from a compliance perspective. On R5, the wording should be changed from "absolute value is at least equal to" to

Organization	Yes or No	Question 2 Comment
		"absolute value is greater than or equal to"
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **The SDT has also included other methods that a BA can use to provide Frequency Response in the Background Document.** **The SDT has added language to Attachment A to address changes in a BAs footprint.** **The proposed standard is not putting a requirement on the ERO. There is language in the Attachments to provide additional time for a BA to become compliant if the ERO is late in providing the necessary information. If the ERO does not provide the necessary information then the BA would not be required to modify anything and therefore the last information provided would be that which would be used for compliance purposes.** **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.**		
South Carolina Electric and Gas	No	The utilization of the term, "Reserve Sharing Group", is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as "Frequency Response Sharing".

Organization	Yes or No	Question 2 Comment
		R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in "Tie Line Bias" mode.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives. FRSG performance may be calculated on one of two ways: • Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or • Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance. The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.		
Tri-State G & T Association, Inc.; Tucson Electric Power Co.; U.S. Army Corps of Engineers; South California Edison ; Platte River Power Authority; Pacific Gas and Electric Company; Colorado Springs Utilities; Idaho Power	Negative	We believe that there are several modifications that, if implemented to the existing requirements, would result in an improved, clarified standard. As drafted, Requirement R1 requires Balancing Authorities or Reserve Sharing Groups (RSGs) to achieve an annual Frequency Response Measure (FRM) that is equal to or more negative than its Frequency Response Obligation (FRO). As RSGs exist today, FRM performance by an RSG is not contemplated in the definition of FRM and appears to apply more towards 'secondary response'. Recommend clarifiying this concept and possibly including an example in the background

Organization	Yes or No	Question 2 Comment
Company; California Energy Commission; California ISO; Deseret Power		document to help explain how this would work. Requirement R3 requires each Balancing Authority not receiving Overlap Regulation Service to operate its AGC in Tie Line Bias mode... unless such operation would have an Adverse Reliability Impact on the Balancing Authority's Area. There may be occasions in which an entity needs to perform testing or other instances where it is necessary or desirable to operate in a mode other than Tie Line Bias that does not qualify as an Adverse Reliability Impact, but never the less is necessary or desired. Recommend including language that would permit operation other than Tie Line Bias mode provided the Reliability Coordinator was notified. We seek clarification from the drafting team as to whether or not there will be any conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction.

Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**
- **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**

The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.

Organization	Yes or No	Question 2 Comment
The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.		
ISO New England Inc	No	We do not agree with placing a requirement on Balancing Authorities, as generators are the main supplier of "discretionary" frequency response. Also, the requirement refers to an attached form, which is not part of the standard and therefore not enforceable.
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **If an attachment is referenced in a requirement that attachment becomes part of the requirement. However the requirement has been modified to no longer reference an attached form.**		
SERC OC Standards Review Group	No	We feel that the utilization of the term, "Reserve Sharing Group", is not consistent with the definition in the NERC Glossary of Terms, and should be deleted, applicability should be clarified or replaced with a new term, such as "Frequency Response Sharing". R2 exempts BAs participating in Overlap Regulation Service from implementing the Frequency Bias Setting on the date specified by the ERO, and R4 states how the BA

Organization	Yes or No	Question 2 Comment
		performing Overlap Regulation Service will modify its Frequency Bias Setting but does not state when the setting will be implemented. The exemption for BAs participating in Overlap Regulation Service should either be deleted from R2 or language stating the implementation date of the frequency bias setting needs to be included in R4. R4 should clarify that a BA performing Overlap Regulation Service should still be required to operate its AGC in "Tie Line Bias" mode.

Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of the FERC's Order No. 693 directives.

FRSG performance may be calculated on one of two ways:

- **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**
- **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**

The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response.

The SDT has modified the language in Requirement R2. The term "not participating in" has be replace with "not receiving". This now encompasses entities that are providing Overlap Regulation Service.

The SDT has removed the requirement to operate AGC in Tie Line Bias mode as this requirement was duplicative of the Requirements R6 and R7 in BAL-005-0.1b.

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency/JEA Electric Compliance	No	We thank the SDT for their hard work and diligence in moving this Project forward. However, we have some concerns that cause us to not support the standard in its current form. In general, we believe that there has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. We also believe that the proposed standard does not meet all of the conditions of the Final SAR and Supplemental SAR.The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states:”The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once thereasons for the decline in Frequency Response are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters.”BAL-003-1 does not seem to complete the scope of this “Final SAR”. For instance, “the reasons for the decline in Frequency Response” were not confirmed to our knowledge; and the field trial is not completed to our knowledge.The Supplemental SAR adds to the scope of the Final SAR:”To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys.”The Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing “defined reliability parameters”. In addition, the standard does not complete the requirement of the Supplemental

Organization	Yes or No	Question 2 Comment
		SAR to identify "methods to obtain Frequency Response". For instance, neither the BA nor the RSG have authority over governor and other generator settings. There should be a requirement for GOPs to incorporate setting changes directed by the BA, otherwise the standard establishes requirements that BAs and RSGs may not have the authority to achieve. There is no consideration of "footprint" changes of the BA resulting in different allocation from the ERO during a year. The standard and Attachments seem to specify an annual process with due dates in December and January with no allowance for mid-year changes and associated allocation changes. If a standard has a requirement for the ERO, who will audit the ERO for compliance? If the ERO does not meet its obligations, can an entity still be found non-compliant, especially on a schedule basis? Wasn't there an issue of assigning standards to RROs, e.g., the fill-in-the-blank standards? Are there similar issues with assigning requirements to the ERO? Is the ERO a "user, owner or operator" of the BPS under Section 215, e.g., at (b)(1)"… All users, owners and operators of the bulk-power system shall comply with the reliability standards that take effect under this section." We question how this would work from a compliance perspective.

Response: The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.

The SDT agrees that the original SAR was strictly for data collection. However, a supplemental SAR was developed to address the FERC March 18, 2010 Order and was subsequently approved by the industry. The Standards Committee has determined that a proposed standard must be within the scope of the approved SAR but the proposed standard is not required to address the full scope of the SAR if stakeholders support a reduced scope.

The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

Organization	Yes or No	Question 2 Comment
The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **The SDT has also included other methods that a BA can use to provide Frequency Response in the Background Document.** **The SDT has added language to Attachment A to address changes in a BA's footprint.** **The proposed standard is not putting a requirement on the ERO. There is language in the Attachments to provide additional time for a BA to become compliant if the ERO is late in providing the necessary information. If the ERO does not provide the necessary information then the BA would not be required to modify anything and therefore the last information provided would be that which would be used for compliance purposes.**		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Florida Power & Light Company	Yes	
Independent Electricity	Yes	

Organization	Yes or No	Question 2 Comment
System Operator		
Associated Electric Cooperative Inc	Yes	
Cleco Corporation	Yes	
Keen Resources Asia Ltd.	Yes	

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

Summary Consideration: The majority of the commenters agreed with the VRFs that the SDT has proposed for the requirements within the standard.

One commenter felt the VRFs were too high and that they should have a "lower" VRF. The SDT developed the VRFs using the NERC Violation Risk Factor guidelines approved by FERC. A lower VRF is an administrative type of 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. Violation of any of the requirements in the proposed standard 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.

Another commenter stated that they could not fine the "Risk Severity Levels" in the standard. The SDT is not sure as to the meaning of this comment. The SDT believes that the commenter may have been mixing two different terms, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). The question asked by the SDT was concerning the VRFs. These are located within the body of the Requirement. The VSLs are located towards the end of the proposed standard.

Organization	Yes or No	Question 3 Comment
Seattle City Light	Negative	Answer: Yes. Comments: LADWP and SCL agree with the following VRFs: - R1 - Medium - R2 - Medium - R3 - Medium - R4 - Medium - R5 - Medium
Response: The SDT thanks you for your clarifying comment.		
Energy Mark, Inc.	No	Comment 5: See comments in the non-binding poll.
Response: Please see our response to your comments from the non-binding poll.		
Florida Power & Light Company	No	Could not find the Risk Severity Levels in the documents.

Organization	Yes or No	Question 3 Comment
Response: The SDT is not sure as to the meaning of your comment. The SDT believes that you may be mixing two different terms, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). The question asked by the SDT was concerning the VRFs. These are located within the body of the Requirement. The VSLs are located towards the end of the proposed standard.		
Cleco Corporation	No	Please note Cleco does not use the VRFs therefore we feel too much energy and time is spent on the VRFs. The SDT needs to concentrate on the requirements and measurements.
Response: The SDT thanks you for your clarifying comment.		
Ameren	No	This is problematic since for a single BA interconnection these could be argued to be appropriate VRFs, but is different for a multiple BA interconnection, where the risk that a single BA would pose to the interconnection would be Lower.
Response: The SDT developed the VRFs using the NERC Violation Risk Factor guidelines approved by FERC. This document can be found at http://www.nerc.com/files/Violation_Risk_Factors.pdf. IA lower VRF is an administrative type of requirement that, if violated 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. Violation of any of the requirements in the proposed standard 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.		
Seattle City Light/Los Angeles Department of Water and Power	Yes	LADWP and SCL agree with the following VRFs:- R1 - Medium- R2 - Medium- R3 - Medium- R4 - Medium- R5 - Medium
Response: The SDT thanks you for your affirmative response and clarifying comment.		
NV Energy	Yes	Medium appears to be reasonable and appropriate.
Response: The SDT thanks you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Imperial Irrigation District	Yes	
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	
ISO/RTO Council Standards Review Committee	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Southern Company	Yes	
FMPP	Yes	

Organization	Yes or No	Question 3 Comment
ISO New England Inc	Yes	
Tucson Electric Power	Yes	
Independent Electricity System Operator	Yes	
Associated Electric Cooperative Inc	Yes	
American Electric Power	Yes	
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	
Constellation Energy Commodities Group	Yes	
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Duke Energy	Yes	
Keen Resources Asia Ltd.	Yes	

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

Summary Consideration: Many of the commenters were concerned with the language in Requirement R3 stating that an entity had to be operating in Tie Line Bias mode unless there were adverse affects on the BES and that if the requirement was modified that the measure should be modified. The SDT explained that it had removed this requirement from the proposed standard since they felt it was duplicative of Requirement R6 and R7 in BAL-005-0.1b.

Some commenters objected to the definition for FRM and the Measure referencing another document (FRS Form 1). The SDT explained that it modified the definition for FRM to no longer reference another document. The revised definition reads "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

A couple of the commenters had concerns with Requirement R5 in that it should reference "natural Frequency Response" as a third bullet. The SDT has explained that it removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT did not include the term "natural Frequency Response" within the standard itself but included it in the Background Document and Attachment A. The SDT felt that this provided additional clarity within the requirement and allowed for further explanation of the term in the Background Document and Attachment A.

Some commenters indicated that the use of an RSG as a method for supplying Frequency Response was not fully explained. The SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

A couple commenters wanted the sampling interval to be tuned on a per Interconnection basis to support HQTE's characteristics. The SDT agreed and explained that it adjusted the event selection criteria to address concerns related to response driving frequency back to pre-event level during the B value measurement period and this adjustment should address their concern.

Organization	Yes or No	Question 4 Comment

Organization	Yes or No	Question 4 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.
Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.**		
Constellation Energy Commodities Group	No	Based on language modifications proposed to the Requirements, the measures should be revisited.
Response: The SDT has revised the Measures to align with modifications made to the Requirements.		
Xcel Energy	No	Based on our suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language.
Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b.		
MRO NSRF	No	Based on suggested changes to R3 in response to Question 2, the drafting team should modify M3 to be consistent with the proposed language. Additionally, M1 should be revised to not reference a specific Form. The Form may be the format of choice but it should not be an implied requirement. Measures 3 and 4 identify the use of “operating logs” as evidence. Measure 2 identifies hard copy and electronic evidence, “or other evidence”. We suggest calling out specifically “operator logs” for M2 also, in case there are system problems in capturing hard copy or electronic evidence during the short time window for implementation.
Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b. **The SDT has modified Measure M1 which no longer references a form but does reference Attachment A to align with the requirement.**		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">The SDT is only providing examples ("…such as…") of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA believes that historian data should be able to be used for evidence.</td></tr>
<tr><td colspan="3">Response: The SDT is only providing examples ("…such as…") of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard. The SDT believes that the data from the software program "Historian" could be used to demonstrate compliance..</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>It should be clarified that R1 requirement applies to a BA, where the BA doesn't belong to an RSG, or to an RSG. As it is currently drafted, the standard applies to each BA and each RSG. It is redundant in that each BA would need to comply, whether or not they are a member of an RSG that would also be required to comply.

Further, the NERC Glossary definition of an RSG is a group of BAs that collectively maintain, allocate and supply operating reserves. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an RSG if the RSG Agreement allows for such delegation.</td></tr>
<tr><td colspan="3">Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has modified the Applicability Section to clarify when a BA or FRSG is accountable for compliance.

The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."</td></tr>
<tr><td>Tucson Electric Power</td><td>No</td><td>It should be clear that historical data may be used to show compliance.</td></tr>
<tr><td colspan="3">Response: The SDT is only providing examples ("…such as…") of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard. The SDT believes that the data used to reflect compliance would have to</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
be historical data.		
Seattle City Light/ Los Angeles Department of Water and Power	No	LADWP and SCL recommend that the Measures for Requirement 3 and Requirement 5 reflect their comments to Question 2.
Response: The SDT has removed Requirement R3 as it is duplicative of Requirements R6 & R7 in BAL-005-0.1b. The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.		
ISO/RTO Council Standards Review Committee	No	M1: The measure should not be tied to a specific Form. If a BA has the evidence but does not provide it on a given Form, how is the reliability of the Power System impacted? The Form may be the format of choice but it should not be an implied requirement. M4: This measure does not read quite right. Something seems to be missing in the part that says: "...showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4." This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."
Response: The SDT has modified Measure M1 which no longer references a form, however it does reference Attachment A to align with the associated requirement. The SDT is only providing examples ("…such as…") of what could be used to reflect compliance. Other evidence can be used as long as it reflects compliance with the standard. The SDT has modified the Measure M4 to incorporate your suggested wording.		
Independent Electricity	No	M4: This measure does not read quite right. Something seems to be missing in the

Organization	Yes or No	Question 4 Comment
System Operator		part that says: "...showing when Overlap Regulation Service is provided including Frequency Bias Setting calculation to demonstrate compliance with Requirement R4." This part might have read something like: "...showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation or it calculated the Frequency Bias Setting meeting the conditions specified in Requirement R4."
Response: The SDT has modified the Measure M4 to incorporate your suggested wording.		
ERCOT	No	Measure should be modified to align with revised Requirements per ERCOT's comments on #1.
Response: The SDT has modified the Measures to align with the modifications to the Requirements.		
SERC OC Standards Review Group/ Progress Energy/ South Carolina Electric and Gas/ Duke Energy	No	See comments in Question 2 regarding utilization of the term "Reserve Sharing Group".
Response: Please see our response to your comments on Question 2 regarding "Reserve Sharing Group".		
Northeast Power Coordinating Council/ISO New England Inc.	No	The sampling interval needs to be tuned on a per Interconnection basis to support HQTE's characteristics.
Response: The SDT adjusted the event selection criteria to address concerns related to response driving frequency back to pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.		
Florida Power & Light Company	No	What is meant by documented formulae for M5? Is a one time snapshoot of the AGC formual sufficien? The concept is ok but this needs clarification of proof.
Response: The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3.		

Organization	Yes or No	Question 4 Comment
Southwest Power Pool Regional Entity	Yes	Measures are more specific and measurable than seen in the past. This is a positive improvement.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Ameren	Yes	With the understanding that any suggested changes to the proposed requirements would come with corresponding changes to their measure.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT agrees that any modification to a Requirement would necessitate a re-evaluation of the corresponding Measure.		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	
Associated Electric Cooperative Inc	Yes	
NV Energy	Yes	
Cleco Corporation	Yes	

Organization	Yes or No	Question 4 Comment
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	

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

Summary Consideration: Most of the commenters indicated that VSLs for Requirement R1 should not include language tied to whether or not a BA is in a single BA Interconnection or a multi-BA Interconnection. Frequency Response is an Interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA whose performance is 70% of its' FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.

Several commenters did not agree with the VSLs for Requirement R3. The SDT removed Requirement R3 from the revised standard since the requirement was duplicative of Requirement R6 & R7 in BAL-005-0.1b.

With concerns about the use of the RSG as a means to provide Frequency Response, the SDT modified the Background Document to further explain how an RSG (now FRSG) could be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

Organization	Yes or No	Question 5 Comment
Seattle City Light	Negative	Answer: No. Comments: LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative		

Organization	Yes or No	Question 5 Comment
with R6 and R7 in BAL-005-0.1b.		
Public Utility District No. 1 of Douglas County	Negative	1. The BA and interconnection meet the FRO differently. Suggest removing the interconnection performance from the VSL and develop additional levels of BA failure to meet its FRO.
Response: The drafting team does not agree, but believes an explanation would be helpful. **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.** **Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.**		
BrightSource Energy, Inc.	Negative	The negative vote from BrightSource is related to the proposed VSL only. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response: The drafting team does not agree, but believes an explanation would be helpful. **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's**		

Organization	Yes or No	Question 5 Comment
impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
U.S. Army Corps of Engineers; Platte River Power Authority; Pacific Gas and Electric Company; Idaho Power Company; Colorado Springs Utilities; California Energy Commission; California ISO; Clark Public Utilities; Tucson Electric Power Co.; Tri-State G & T Association, Inc.	Negative	The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response: The drafting team does not agree, but believes an explanation would be helpful. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response		

Organization	Yes or No	Question 5 Comment
Obligation.		
Kansas City Power & Light Co.	Negative	The VSL for Requirement 3 does not sufficiently reflect a thoughtful range of violation severity of duration or number of instances by which AGC is not in Tie-Line Bias mode.
Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.		
ACES Power Marketing; East Kentucky Power Coop.; Hoosier Energy Rural Electric Cooperative, Inc.	Negative	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own performance.
Response: The drafting team does not agree, but believes an explanation would be helpful. **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.** **Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.**		
Southwest Transmission Cooperative, Inc.	Negative	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own

Organization	Yes or No	Question 5 Comment
		performance. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO. Conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response: The drafting team does not agree, but believes an explanation would be helpful. **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.** **Consider a small BA that whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.**		
Western Area Power Administration	Negative	Under compliance for R1, there is a difference between VSL levels whether the interconnection met is FRO or not. If the interconnection meets it's FRO but a single BA doesn't't meet its share of FRO the violation is considered low VSL, but, if the interconnection dosen't't meet it's FRO the same BA will have a High VSL. Obligation of the individual BA to meet its allocated FRO should always be applicable regardless of what other BAs are doing in the interconnection. This provision creates a disparity amongst BAs and creates a disparate treatment between the BAs who perform compared to those who don't.
Response: The drafting team does not agree, but believes an explanation would be helpful.		

Organization	Yes or No	Question 5 Comment
VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
Ameren Services; Ameren Energy Marketing Co./Ameren	Negative/No	It is not clear how the VSL for R1 uses the "Summation of the BA's FRM", when the requirement is BA or RSG specific.
Response: Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG). FRSG performance may be calculated on one of two ways: • Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or • Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.		
Manitoba Hydro	Negative/No	The Violation Severity Levels for R1 penalize entities more severely depending on how the interconnection as a whole has performed. MH believes that BAs should only be held accountable for issues within their control and that the VSLs for R1 should be revised accordingly.
Response: The drafting team does not agree, but believes an explanation would be helpful. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.		

Organization	Yes or No	Question 5 Comment
Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
Constellation Energy Commodities Group	No	The language in the VSLs for R1 should be revisited based on the proposed language modifications above and should also clearly look to the FRM of a BA, group of BAs or RSG against the BA FRO not an Interconnection FRO.
Response: The drafting team has made conforming changes to VSLs based on wording changes to the Requirements. Regarding the evaluation of the Interconnection, the drafting team does not agree, but believes an explanation would be helpful. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation. Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG). FRSG performance may be calculated on one of two ways:		

Organization	Yes or No	Question 5 Comment
• **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or** • **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**		
Bonneville Power Administration	No	BPA believes that R1 needs to be more clear and concise as to what is being conveyed in the requirement. It is difficult to understand. The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.BPA believes that conforming changes to the VSLs would need to be made for any changes to the Requirements as suggested in the comments to the standard.
Response: The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. We would welcome suggested wording changes that relay this concept more clearly. **With regard to removing a view of Interconnection performance, the drafting team does not agree, but believes an explanation would be helpful.** **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.** **Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency**		

Organization	Yes or No	Question 5 Comment
Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
Florida Power & Light Company	No	For R1 the low and high level descriptions appear to be identical and the high level is less than the medium risk level. For R3 there should be low, medium, and high levels. One BA not operating to TLB does not jepordize the Interconnection. Additionally, computer failures, database loads etc may require some period where TLB is not in service. Suggestion would be Lower VSL operation off of TLB for more than 5 but < 8 continuous hours or accumlative during the year of more than 8 < 16 hours. Medium VSL would be operation off of TLB for more than 8 but <16 continuous hours or accumlative during the year of more than 16 <24 hours. High VSL would be operation off of TLB for more than 16 <24 continuous hours or accumlative during the year of more than 36 <48 hours. Severe VLS would be >24 continuous hours off of TLB or accumlative of > 48.
Response: The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation. **Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.**		
NV Energy	No	For R1, suggest that the VSL's not be dependent upon the aggregate performance of the BA's within an interconnection.
Response: The drafting team does not agree, but believes an explanation would be helpful. **VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.**		

Organization	Yes or No	Question 5 Comment
Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
American Electric Power	No	It is not clear for R1 what the exact delineations are among Lower, Medium, High, and Severe VSL's.
Response: The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
Seattle City Light	No	LADWP and SCL recommend that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 andR7 in BAL-005-0.1b.		
Los Angeles Department of Water and Power	No	LADWP recommends that either the VSL for Requirement 3 reflects its comments to Question 2, or that these comments be addressed as an exception in the Measure for Requirement 3.
Response: Based on Industry comments and further review, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.		
ReliabilityFirst	No	ReliabilityFirst thanks the SDT for their effort on this project. ReliabilityFirst has a number of concerns/questions related to the draft BAL-003-1 VSLs which include

Organization	Yes or No	Question 5 Comment
		the following: 1. General VSL Comment - For consistency with other standards, each VSL should begin with the phrase “The Responsible Entity...” or “The Balancing Authority”. This is consistent with the language of the requirement and correctly pinpoints the appropriate responsible entity. 2. VSL R1 Comment - Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”. ReliabilityFirst suggests the following modification:a. Lower VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection’s FRO and the Responsible Entity’s FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FROb. Medium VSL - The Responsible Entity achieved an annual FRM within an Interconnection that was equal to or more negative than the Interconnection’s FRO and the Responsible Entity’s FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FROc. High VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity’s, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FROd. Severe VSL - The responsible entity failed to achieve an annual FRM that is equal to or more negative than its FRO and the Responsible Entity’s FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO3. VSL R4 Comment - Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”. ReliabilityFirst suggests the following modification: a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority incorrectly modified the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined

Organization	Yes or No	Question 5 Comment
		footprint setting-error less than 5% of the validated or calculated value4. VSL R5 Comment - Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”. ReliabilityFirst suggests the following modification: a. Example for Lower VSL which should be carried throughout all four VSLs - The Balancing Authority used a monthly average Frequency Bias Setting whose absolute value was less than or equal to 5% below the minimum specified by the ERO.
Response: While there may be a better way to lay out the VSL, the VSL for R1 is consistent with R1 in that performance can be reported either as a single BA or as an RSG. The “Lower” and “Medium” VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation. **The drafting team has modified the VSLs for R4 based on your comments. The SDT removed Requirement R5 and combined it into revised Requirement R2 and new Requirement R3.**		
Progress Energy / South Carolina Electric and Gas/Duke Energy	No	See comments in Question 2 regarding utilization of the term “Reserve Sharing Group”.
Response: Based on comments, the drafting team has created a new definition for an entity called a Frequency Response Sharing Group (FRSG). **Similar to traditional Reserve Sharing Groups for Contingency Reserves, FRSGs as proposed in this standard , are voluntary organizations whose members determine the terms and conditions of participation. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRFSGs, but allows them as a means to meet one of the FERC’s Order No. 693 directives.** **FRSG performance may be calculated on one of two ways:** • **Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or**		

Organization	Yes or No	Question 5 Comment
• **Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual annual performance.**		
SERC OC Standards Review Group	No	See comments in Question 2 regarding utilization of the term "Reserve Sharing Group". VSL for R1:The draft VSLs for R1 uses the summation of FRM for all BAs within an Interconnection as a factor in determining the applicable VSL. This does not seem consistent with R1. R1 is about a single BA and the individual BA's frequency response performance as measured by the FRM for that specific BA. Including the FRM summation of the Interconnection expands R1. It appears that a BA that is non-compliant with R1 could end up with either a Low/Medium or High/Severe VSL based upon the FRO performance of the Interconnection. The FRM performance of the Interconnection is beyond the knowledge and control of a single BA and should not be a determinate of the applicable VSL.Is there a technical basis for selection of the 1%, 30% and 15MW/.1 Hz VSL breakpoints? Does the Lower VSL give a 1% dead band to a BA's FRO? If so, will this be acceptable to NERC/FERC? VSL for R2:The VSL should reflect the language used in the requirement. R2 says a BA "not participating in Overlap Regulation service shall ....", while the VSL says a BA "not receiving Overlap Regulation Service....." The VSL language is not consistent with the requirement. VSLs for R5:Since Frequency Bias Setting is expressed as a negative value, the terms "absolute value" and "less than" must be used carefully. Wouldn't the "absolute value" of a BA's Frequency Bias Setting always be positive and thus it could never be less than the minimum specified by the ERO (a negative value)?
Response: With regard to R1, VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections.		

Organization	Yes or No	Question 5 Comment
The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation. Regarding the 1%, 30% and 15MW breakpoints, the 1% value accommodates rounding error. The 30% or 15MW/0.1Hz is intended to comparably address both large and small BAs. The drafting team used its judgment in selecting these values and cannot predict what the FERC might accept. The SDT has modified the VSLs for Requirement R2 to correctly match the requirement. The SDT has removed Requirement R5 from the proposed standard and combined it into Requirements R2 and R3. Requirement R2 no longer references "absolute value" and Requirement R3 references "absolute value" only as a comparison to another "absolute value".		
Western Electricity Coordinating Council	No	The proposed VSLs for Requirement R1 treat a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: The drafting team does not agree, but believes an explanation would be helpful.

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Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response.

To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections.

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<tr><td>JEA Electric Compliance/ MRO NSRF</td><td>No</td><td>The proposed VSLs for Requirement R1 treats a BA that did not meet the FRO requirement differently depending on whether or not the Interconnection met the FRO requirement. The obligation of the BA to meet its allocated FRO should be consistent regardless of what the other entities within the interconnection are doing. Suggest removing the interconnection performance from the VSLs and developing four increasing levels of BA failure to meet its FRO.</td></tr>
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Northeast Power Coordinating Council	No	The violation severity levels for R1 are reasonable. The technical writing needs to be enhanced for clarity.
Response: Thank you for the comment. The drafting team will look at ways to clarify the wording or provide an explanation in the Background Document.		
ISO New England Inc	No	The violation severity levels for R1 seem to be reasonable. However, the technical writing needs to be enhanced for clarity
Response: Thank you for the comment. The drafting team will look at ways to clarify the wording or provide an explanation in the Background Document.		
SPP Standards Review Group/Cleco Corporation	No	The VSLs for R2 are based on 5, 15 and 25 days. What was the justification for these values? Could we just as well use 10, 20 and 30 or some other set of values? In R3, we understand that brief periods of operation outside of TLB control are allowable providing 1) continued operation in TLB control would create ARI on the Interconnection or 2) that justification is provided for the periods when TLB is not used. For example, if something happens within our EMS that disables TLB control

Organization	Yes or No	Question 5 Comment
		are we compliant if we document the period as an EMS malfunction?
Response: Regarding R2, the time windows were based on judgment of the drafting team. Similar to the commenters' question, the team could have chosen 1, 7, 14 and 28 days or 1, 2, 3 or 4 days to frame the four levels of VSLs. The SDT has modified Attachment A to allow an implementation window of 3 days for implementation of the Frequency Bias Setting. With regard to R3, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.		
ACES Power Marketing Standards Collaborators/Great River Energy	No	The VSLs on for Requirement R1 set a previously un-established precedent of relying on the performance of other registered entities to establish the severity level of the violation. This is not appropriate. The VSLs should be rewritten to provide further gradations of the violation severity based on the BA's own performance.
Response: The drafting team does not agree, but believes an explanation would be helpful. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively. However, the SDT has added language to the requirement to reference the Interconnection Frequency Response Obligation.		
Southern Company	No	VSL for R2:We suggest the language in the VSL be consistent with the language

Organization	Yes or No	Question 5 Comment
		used in the Requirement. The VSL for R2 says a BA 'not receiving Overlap Regulation Service.......' R2 says a BA 'not participating in Overlap Regulation service shall ....' VSLs for R5:Since Frequency Bias Setting is expressed as a negative value, the terms "absolute value" and "less than" must be used carefully. This VSL uses "absolute value" when referring to the BA's Frequency Bias Setting, but does not use "absolute value" when referring to the Frequency Response Obligation, or minimum value specified by the ERO. Consider revising this VSL so that a true comparison can be made.
Response: We agree with your suggested change for the VSL for R2 and corrected the mismatch between the requirement and the VSLs. **The SDT has removed Requirement R5 from the proposed standard and combined it into Requirements R2 and R3. Requirement R2 no longer references "absolute value" and Requirement R3 references "absolute value" only as a comparison to another "absolute value".**		
Tucson Electric Power	No	VSL's could be clearer and simpler. Allowance for the testing of other AGC modes should be considered.
Response: The drafting team has made changes to VSLs based on specific suggestions. Regarding AGC operation, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.		
Southwest Power Pool Regional Entity	Yes	Hard to follow the language for the VSL for R1. Suggest using formulas for ease of interpretation or provide an example in the Supporting Documentation.
Response: The drafting team will provide an explanation in the Background Document.		
Associated Electric Cooperative Inc	Yes	The VSLs appear reasonable for the risk and particularly where they assess higher severity when the BA or RSG Interconnection's performance was sub-standard as well.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment.		
ISO/RTO Council Standards Review Committee	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
Response: The drafting team agrees and has made this change.		
Independent Electricity System Operator	Yes	We do not have any issues with the VSLs, but wonder if the wording for R1 should have been "...Reserve Sharing Group's...". Alternatively, the wording after "interconnection's FRO" could be revised to: "...and the Balancing Authority's or the Reserve Sharing Group's FRM was..."
Response: The drafting team agrees and has made this change.		
Texas Reliability Entity	Yes	We suggest that the Severe VSL for R3 is confusing and should be clarified as follows: "A Balancing Authority not receiving Overlap Regulation service failed to operate AGC in Tie Line Bias mode, when operation in Tie Line Bias mode would not have had an Adverse Reliability Impact on the Balancing Authority's Area."
Response: Regarding AGC operation, the drafting team has deleted R3 as the requirement is duplicative with R6 and R7 in BAL-005-0.1b.		
Imperial Irrigation District	Yes	
Salt River Project	Yes	
Energy Mark, Inc.	Yes	
FMPP	Yes	

Organization	Yes or No	Question 5 Comment
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Keen Resources Asia Ltd.	Yes	

6. **The SDT divided the previously posted "Attachment A – Background Document" into two documents to provide additional clarity. The first document "Attachment A- Supporting Document" which details the methods used to develop the events to be analyzed, the FRO, FRM and Frequency Bias Setting. Do you agree that the revised Attachment A – Supporting Document provides sufficient clarity on the methodologies to be used? If not, please explain in the comment area.**

Summary Consideration: The majority of the commenters pointed out that there was a discrepancy between Attachment A and the Background Document concerning the methodology used to calculate FRO. The SDT addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that Interconnection.

Several of the commenters indicated that the proposed standard did not provide a limit on the amount of Frequency Response that a BA was supposed to provide. The SDT added Paragraph #8 in Attachment A under the Event Selection Criteria to clarify that events greater than the limit in the criteria would be capped at a certain limit. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.

Some commenters were confused about the intent of Attachment A. They indicated that Attachment A was describing both a methodology to select events and providing a background for the process (not a process/methodology). The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry.

As to the use of the term "may" in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different than an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. If the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure.

A couple of commenters said that using older data for compliance could cause an entity to be in “double jeopardy”. The SDT discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. The drafting team has, however, reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events cannot be found in that period.

A few o commenters indicated that the allocation of the FRO to the BAs was a “top down” approach. The SDT agrees with some of the comments made, but not in the conclusion drawn from the individual points. There is not currently an obligation to provide any amount of frequency response to a sudden change in interconnection frequency. The proposed standard addresses this shortcoming in the proposed standard.

The drafting team has also reduced the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System.

Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic.

A couple of commenters questioned whether point B was 18 seconds after the start of the disturbance. The SDT revised the language in the document to provide clarity on the 18 seconds. To the extent that the language is related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available.

Organization	Yes or No	Question 6 Comment
Western Area Power Administration, Western Area Power Administration - UGP Marketing	Negative	4. The allocation of FRO among BAs is a top-down approach instead of bottom up approach currently used. Currently, BAs calculate their FRC and set their Bias based on the greater of 1% peak load (1% generation for gen only BAs), or the average of frequency response characteristic of their BA over a year (FRC). These calculated individual biases get summed up and it becomes the Interconnection Bias value. The proposed standard has identified a set MW (for Western Interconnection 685 MW for

Organization	Yes or No	Question 6 Comment
		0.1 of HZ) and is allocating it among all BAs. The individual BA's allocated FRO is much lower than what BAs obligations' presently are since the proposed standard lowers the bar for the BAs. The current approach is definitely superior to what is proposed since it more closely matches with the characteristic of the system and it protect the interconnection by requiring larger contribution than proposed standard. 5. The allocation of FRO among the BAs in the interconnection favors the BAs with more load than more installed capacity
Response: 4. The drafting team agrees with some of the comments made here but not in the conclusion you draw from the individual points. There is not currently an obligation to provide any amount of frequency response to a sudden change in the interconnection frequency. The proposed standard addresses this shortcoming in the current standard. The drafting team has also reduced the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System. Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic. Please refer to Order 693 P371 for further information on this issue. **5) After further discussion, the drafting team believes that the proposed allocation methodology does not favor any specific type of entity. To the extent that the commenter believes that the allocation favors any specific type of entity, the commenter should provide detailed reasoning of its position, not just an unsupported statement. The drafting team was unable to find any basis for this position during our discussions of the proposed allocation methodology. The drafting team will also point out that installed capacity is not a part of the calculation. The proposed allocation methodology, which has been clarified in the revised documents, utilizes monthly average peak generation and average peak load.**		
Seattle City Light	Negative	Answer: No. Comments: o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.

Organization	Yes or No	Question 6 Comment
Response: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not be used consistently across the industry.		
Alliant Energy Corp. Services, Inc.	Negative	Confusion exists around the "peak load" in that Attachment A states the allocastion is based on Projected Peak Loads and Generation but the Background Document states it will use historical Peak and Generation to make the allocation. - There appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation in Attachment A, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity of something less - please clarify. – It is not clear if there is an upper limit to the amount of frequcncy response expected of the BA's under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. BA's need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet the requirements.
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. **The drafting team has added a paragraph in the FRM section of Attachment A limiting the amount of Frequency Response for which a BA will be measured for compliance purposes. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.**		
BrightSource Energy, Inc.; Clark Public Utilities; Tri-State	Negative	Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, but

Organization	Yes or No	Question 6 Comment
G & T Association, Inc.; Tucson Electric Power Co.; U.S. Army Corps of Engineers; South California Edison ; Platte River Power Authority; Pacific Gas and Electric Company; Colorado Springs Utilities; Idaho Power Company; California Energy Commission; California ISO; Deseret Power		the Background Document states it will use "historical" Peak Load and Generation. Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response. The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz or in the Western Interconnection that causes the frequency to drop to less than 59.5 Hz, or if that event is excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, it is unclear what is expected of the Balancing Authorities. Finally, why are there no requirements on governor installation, settings, and operation for a frequency response standard?
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. **A reduction in the Frequency Bias Setting (FBS) may reduce the amount of AGC responses to a change in frequency. However, the drafting team has ensured that the FBS does not dip below the actual frequency response to ensure that the Frequency Response**		

Organization	Yes or No	Question 6 Comment
is not withdrawn due to AGC action. With that said, there is currently not an obligation to provide any amount of frequency response to a sudden change in the interconnection's frequency. The proposed standard addresses this shortcoming in the current standard. The drafting team has modified the initial reduction in the minimum Frequency Bias Setting to ensure that the reduction can be studied closely to ensure no detrimental impact on the reliable operation of the Bulk Electric System. Finally, there is ongoing disagreement in the industry as to whether it is desired to have a minimum Frequency Bias Setting that is significantly greater than the Frequency Response Characteristic. Please refer to Order 693 P371 for further information on this issue. **The drafting team has added a paragraph in the FRM section of Attachment A limiting the amount of Frequency Response for which a BA will be measured for compliance purposes. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.** **The drafting team is operating under the Standard Authorization Requests (SARs) as approved. This drafting team believes that proposing a generator requirement is beyond the scope of the SARs. To the extent that the commenter believes there is a need to have a reliability standard related to generators, the drafting team would suggest that the commenter submit a SAR to begin the development process.**		
Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.	Negative	On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one year to the next in FRO or Bias settings assigned by the ERO. On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection? The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to "false trip".", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.
Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy		

Organization	Yes or No	Question 6 Comment
concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events cannot be found in that period. **The drafting team modified the language to clarify that the ERO will set the IFRO.** **This modification was made.**		
Salmon River Electric Cooperative	Negative	We feel that the drafting team has done an excellent job of providing clarify and reasonable reporting requirements to the right functional entity. We support the modifications but would like to have two additional minor modification in order to provide additional clarification to the Attachment I Event Table. We suggest the following clarifications: For the Event: BES Emergency resulting in automatic firm load shedding Modify the Entity with Reporting Responsibility to: Each DP or TOP that experiences the automatic load shedding within their respective distribution serving or Transmission Operating area. For the Event: Loss of Firm load for = 15 Minutes Modify the Entity with Reporting Responsibility to: Each BA, TOP, DP that experiences the loss of firm load within their respective balancing, Transmission operating, or distribution serving area. With these modifications or similar modifications we fully support the proposed Standard.
Response: The drafting team understands that this comment was submitted under the wrong project.		
FMPP	No	o Item 2 should be changed as follows: The ERO will identify at least 25 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify in a given evaluation period 25 frequency excursion events satisfying the limits specified in criteria 3 below, then similar acceptable events from the previous evaluation period also satisfying listed criteria will be included with the data set by the ERO for determining FRS compliance. (as written this item could cause double jeopardy for event from the previous period) o Under FRO for the Interconnection the first sentence should be changed as follows: "The ERO {Each Interconnection (delete these words)} will establish target

Organization	Yes or No	Question 6 Comment
		contingency protection criteria for each Interconnection." (each Interconnection is not a governing entity) o The footnote under Table 2 of Attachment A should be changed as follows: The Eastern Interconnection set point listed is a compromise value for the highest UFLS step setting of 59.5Hz used in the east and the {special protection scheme's (delete these words)} highest UFLS step setting of 59.7Hz used in Florida. It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS {special protection scheme (delete these words)} to "false trip". (this is not a special protection system; it is just an UFLS)
Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events cannot be found in that period. **The drafting team modified the language to clarify that the ERO will set the IFRO.** **This modification was made.**		
Seattle City Light	No	o LADWP and SCL consider the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. SCL suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.
Response: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally,		

Organization	Yes or No	Question 6 Comment
the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.		
Manitoba Hydro	No	1. p.2 refers to each “Interconnection” establishing target contingency protection criteria. However, an “Interconnection” as defined in the NERC Glossary is an electrical system, not a Responsible Entity. This should be revised to clarify which Responsible Entities must establish the protection criteria. 2. Table 2, although entitled “Interconnection Frequency Response Obligations” does not use the term FRO in the Table itself. This terminology should be consistent. 3. There is no clear statement in Attachment A identifying the significance of Table 2. The previous paragraph identifies Table 2 as listing “default targets”, but how does this relate to the FRO referenced in R1? 4. The “Note” on p.2 regarding the ERO being able to use additional events that don’t satisfy the criteria is unreasonable as drafted. Since these events are used to calculate the Frequency Bias Setting and FRM (as per p.1, s.2), the selection of events should not be at the unfettered discretion of the ERO. As drafted, no grounds or criteria must be satisfied.
Response:1. The drafting team modified the language to clarify that the ERO will set the IFRO. **2. The drafting team modified the table to ensure consistent terminology is used.** **3. The drafting team modified Attachment A to clarify the importance and explain the calculations made to get to the Interconnection FRO.** **4. The drafting team revised the note to clarify that the ERO may use any event, regardless of size or other condition, in its evaluation of Interconnection Frequency Response. However, these additional events will not be used for evaluation of BA response compliance.**		
FPL	No	3. - How many seconds of observation for “Delta F”? Does “Point C” in a. refer to “Figure 1 - Classic Frequency Excursion and Recovery” from NERC’s Survey

Organization	Yes or No	Question 6 Comment
		Instructions document dated September 1, 2010? If so it should be included in this document along with the added 8 and 18 second time lines being shown. What is a "narrow range" in item b.? 4. - Better define "relatively steady" (i.e. within a specific range and state it?) Also, "near 60.000 Hz" is not precise enough (i.e. if the event begins below 60.000 Hz, what range or time error correction is to be considered acceptable?) Is the "A" value also part of the figure cited in 3? 5. - Is the "B" value also part of the figure cited in 3? 6. - Change "should be excluded" to "will be excluded". 7. - Better explain "the cleanest 2 or 3 frequency excursion events" or remove the word "cleanest". Page 2 paragraph 5: Provide specific dates for the "quarterly postings" and where these will be posted (i.e. Internet address or other). Clarify the December 15 ERO annual post date with the dates stated for same posting on Page 3 paragraph 5 and the BA's January 10 deadline. The BA posts 30 days from which date? This is confusing. Page 2 Table 2: What of starting event frequencies that are < 60 Hz? Why is the "Highest UFLS" 59.6 when the Florida setting for its load is 59.7? Page 3 FRO equation: Page 4 of the "Frequency Response Standard Background Document, October 2011" also shows this equation but uses different terms. Make the same on both documents. In the Background Document each component of the numerator is explained and reference is made to FERC Form 714 to obtain these values. There is no reference to this form for the denominator values. All of this needs to be made clear with reference to FERC Form 714 on Attachment A.
Response: 3. The SDT has modified the titles of the columns in Table 1 of the Procedure document to clarify what was intended by the table. The Point C value is defined in section 3a.		

Organization	Yes or No	Question 6 Comment
4 - Due to the complicated nature of event evaluation and selection, the drafting team has retained the words "relatively steady" and "near 60" in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience in gained, the NERC Resources Subcommittee will attempt to document the process further. **5 – No, the B value is a calculated value not shown in the chart referenced in number 3 above. Additional language has been added in Attachment A to clarify both the A value and the B value. The A and B values are shown on Figure 2 of the Background document as green and red lines, respectively.** **6 – The drafting team modified this language.** **7 – Due to the complicated nature of event evaluation and selection, the drafting team has retained the word "cleanest" in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience in gained, the NERC Resources Subcommittee will attempt to document the process further.** **NERC is developing this part of the process and an area to post this information. The drafting team has put clear language in the attachment requiring at least quarterly posting of events. It is currently the drafting team's expectation that a list of potential events would be posted shortly after they actually occur and a refined list will be made available quarterly.** **Modifications to Table 2 have been made to clarify what is being used.** **Attachment A and the Background Document have been modified so that the FRO Allocation equation is the same and the terms are fully explained.**		
Tucson Electric Power	No	Attachment A creates additional requirements to the BAL-003-1 Standard. The arrested value of frequency observed within 8 seconds may not be long enough in some instances. The delta F in the West should be greater than 0.05 Hz to ensure a measurable frequency response. West Under Frequency should be set at 59.95 Hz. There is no reliability concern for Over Frequency. Does 18 seconds after the start of the disturbance set point B?

Organization	Yes or No	Question 6 Comment
		Pre-disturbance frequency should be relatively steady and near 60.000 Hz is vague. TEP feels that the ERO should not need to validate a BAs frequency bias setting.

Response: The drafting team has modified the standard to put the requirements there and use Attachment A to clarify the process.

After further discussion and review of the events in the Western Interconnection Form 1 for 2011, the drafting team has modified the Delta C and Under Frequency values in Table 1.

Based on language in Order 693 P355, the drafting team believes that frequency response is needed in both directions, not just one.

The drafting team has revised the language in the document to provide clarity on the 18 seconds. To the extent that the language related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available.

Due to level of detail being used to determine the FBS and FRM as well as the interactions between this standard and others, the drafting team disagrees with the commenter and continues to recommend the ERO validate the FBS of each BA.

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	BPA believes that Attachment A adds additional requirements to the standard. Confusion exists between Attachment A and the Background Document. Attachment A states peak load allocation is based on “Projected” Peak Loads and Generation, but the Background Document states it will use “historical” Peak Load and Generation. 3a: it may take longer than 8 seconds in some disturbances. This should be 10 seconds. .05 Hz Delta F is not low enough for the Western Interconnection, it should be .075Hz to ensure there is measurable frequency response for the interconnection. Also, under frequency should be set at 59.95 Hz. BPA does not believe there is a reliability need to include over frequency events.

Organization	Yes or No	Question 6 Comment
		3b: It is unclear if the 18 seconds is setting the B point. If this is the B point, BPA believes it should be changed to 25 seconds for the Western Interconnection. 4. Please define relatively steady and near 60 Hz. 6: For the Western Interconnection, BPA believes this needs to be 10 minutes at the top of the hour. As mid hour scheduling becomes more prevalent, the ramping at the bottom of the hour will have to be taken into account. FRO for the interconnection: Starting frequency should be the FTL limit. With RBC in place, the frequency is seldom at 60 Hz. BPA understands the theory behind setting the base obligation to the values listed in table 2. BPA would like to know if there were any studies performed to validate setting the FRO for the interconnection to such a low level? BA FRO and frequency bias setting: BPA does not agree with ERO assigning a Frequency Bias setting to each BA. This calculation is indicated as the initial FRO allocation, what is the process for changing it? BPA believes this should go through the standard drafting process for any changes. The calculation should use Peak online capacity, not the installed capacity. This would lead to the denominator being 2 X Peak projected load for the interconnection. BPA has approximately 35,000 MW of installed generation, and has never seen the actual coincidental generation go over 21,000 MW. Again, BPA doesn't believe the ERO should be validating the frequency bias setting. It is unclear to BPA how variable bias is being addressed in the standard.

Response: The drafting team has modified the requirements to address comments. The drafting team believes as modified the requirements are stated in the standard and the process to be used is in the Attachment.

The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection.

The drafting team has revised the language in the document to provide clarity on the 18 seconds. The drafting team has also

Organization	Yes or No	Question 6 Comment
attempted to clarify that the B Value is the average of the scan rate data for the period from 20 to 52 seconds following the start of the event. The event selection criteria will use the frequency approximately 18 seconds (prior to the start of the B Value period) to as frequency level to determine if the change in frequency qualifies as an event for the purposes of this standard. Based on event information for the 12 month period beginning December 2010, the drafting team has modified the frequency levels used for event qualification but did not modify the 18 second frequency point. To the extent that the language related to a specific definition of steady frequency, this has been worded intentionally to allow the process being developed by the ERO (specifically the Resources Subcommittee and the Frequency Working Group) to be adjusted based on experience that will only be gained through evaluation of actual events over the course of the next few years. Until that experience is gained, there will need to be some leeway in the process. The drafting team believes that the level of guidance provided in Attachment A is appropriate based on the information currently available. Both the NERC Resources Subcommittee (RS) and the NERC Transmission Issues Subcommittee (TIS) evaluated the level of response needed. The drafting team decided to use the limits determined by the RS over that determined by the TIS after evaluation of both. The documents developed by both of these subcommittees are available on the NERC website under this project (http://www.nerc.com/filez/standards/Frequency_Response-RF.html). The drafting team clarifies that the ERO is not assigning the Frequency Bias Setting. The ERO will review the data to determine that the Frequency Response Measure is correctly determined by the BA and that the Frequency Bias Setting is therefore correct. The expected process is that a subcommittee under NERC will review the Form 1 and Form 2 for each entity to ensure that the BA correctly filled out the form. Assuming the BA has correctly filled out these forms, there is no ERO interaction with the number provided by the BA. The FRO calculation is being included in the Attachment A to ensure that the process to modify the calculation would need to be open to industry input. It is not appropriate to put it in a requirement since it would not make sense to make a requirement that the FRO be allocated in a certain manner. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity. The drafting team revised the requirements to separate the variable bias requirement from the fixed bias setting requirement and provide clarity related to what is expected in a variable bias setting.		
Energy Mark, Inc.	No	Comment 6: “If the ERO cannot identify in a given evaluation period 25 frequency excursion events satisfying the limits specified in criteria 3 below, then similar acceptable events from the previous evaluation period also satisfying listed criteria

Organization	Yes or No	Question 6 Comment
		will be included with the data set by the ERO for determining FRS compliance." I believe that the better alternative in this case would be to use the lesser number of events. This is partly based on the consideration that if there are fewer events, the risk to the interconnection for that year was less that expected, and as a result, evaluation of fewer events will not compromise interconnection reliability. If fewer than 25 events are available in any year, the selection criteria should be adjusted to select more events. Comment 7: There are a number of problems with the use of "median" Frequency Response of the measured events. These problems make a choice other than median preferable. The following comments list some of those problems. Comment 8: The current standard uses average Frequency Response of selected events. This makes the current standard incompatible with the use of median. Comment 9: If a BA reconfigures during a measurement year, that reconfiguration will create a bi-modal distribution of the Frequency Response events. Median is incapable of representing a bi-modal distribution. The use of median will result in a standard that is incapable of measuring compliance effectively for an BA that is reconfigured during a measurement year (Dec 1 thru Nov 30). Comment 10: Any attempt to purchase additional Frequency Response from another BA for a portion of a measurement year will also cause a bi-modal distribution making the purchase of Frequency Response only effective for entire measurement years. Comment 11: Median is a non-linear measurement method. Because it is a non-linear measurement method, there is no valid way to manage partial year measurements. Comment 12: I will offer an alternative to median to the SDT before the end of the development of responses to these comments. Comment 13: The Minimum Frequency Bias Setting and the Frequency Response Obligation are both based on a method that assigns responsibility based on a Peak

Organization	Yes or No	Question 6 Comment
		Load / Peak Generation share of the interconnection. However, the method used to set the Minimum Frequency Bias Setting is different than the method used to determine the Frequency Response Obligation. Using these two different methods could result in the Minimum Frequency Bias Setting being less that the FRO for a BA. The best way to correct this problem is to use that same allocation methodology for determining the FRO and the Minimum Frequency Bias Setting. This can be easily accomplished by modifying R5 to use the FRO allocation method to determine the Minimum Frequency Bias Setting. This calculation would divide the numerator from the FRO allocation equation, divide it by two and multiply it by the percentage specified in Attachment B. In fact, the current FRS Form 1 uses this equation with projected rather than historic data. The best alternative would be to modify the R5 in the standard to match the FRO allocation method and modify FRS Form 1 to use historic data instead of projected data. This would result in only one set of Peak Load and Peak Generation data throughout the standard, rather than three different sets of data as currently written. When multiple sets of the same or similar data are used within a single standard, it only creates confusion and errors in the result.

Response: Comment 6: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.

Comment 7-12: The drafting team is recommending use of the median for the purposes of determining a BA FRM over multiple events. This decision is based on the determination that, while it may not be perfect, it is better than the other alternatives available at this time. The drafting team recognizes that in the future a better methodology might be found; based on the data available at this time the median allows us to move forward to implement a response requirement.

Comment 13: The drafting team understands your concern of using the historical numbers for the FRO allocation and the projected number as the basis for the minimum Frequency Bias Setting. However, after discussions, the drafting team believes

Organization	Yes or No	Question 6 Comment
that at this time, minimizing the changes to the current Frequency Bias Setting process provides better comparability for the purpose of evaluating the impacts of reducing the minimum setting requirement. In the alternative, the drafting team feels that allocating the FRM based on historical data provides less room to game the process since the numbers used for allocation can be verified independently.		
MRO NSRF	No	Confusion exists around the "peak load" in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach.If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify.We suggest the SDT clarify if the materials in the revised Attachment A (and Attachment B) are "Guideline" or "Technical Background", or "requirements
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.		
Xcel Energy	No	Confusion exists around the "peak load" in that the Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where does that value come from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same

Organization	Yes or No	Question 6 Comment
		approach.If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity?
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and monthly peak generation (monthly peak) and does not use installed capacity.		
ISO/RTO Council Standards Review Committee	No	Despite the SDT's good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on P. 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. We suggest that the SDT first determine if the materials in the revised Attachment A (and Attachment B) are "Guideline" or Technical Background", or are they "requirements". If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO's process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA's obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. Further, there are no measures provided for the requirements stipulated/imbedded in Attachment A so how can the Responsible Entity (BA, in this case) be assessed for compliance?We

Organization	Yes or No	Question 6 Comment
		suggest the SDT move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B. Moreover, if the Attachments are to be integral to the standards, the terminology “may” must be replaced with “shall”. Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where appropriate).
Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it’s FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry. As to the use of the term “may” in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different that an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. It the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure. **The SDT agrees with your comment about removing the documents from Section F of the proposed standard has made this modification to the standard.**		
Independent Electricity	No	Despite the SDT’s good faith effort to convert the previous Attachment A into two separate documents (Attachments A and B), the modified Attachment A is

Organization	Yes or No	Question 6 Comment
System Operator		problematic. As many commenters indicated, the previous Attachment A, other than the section providing guidance on event selection, appears to be explanatory, contextual, and instructional in content. These aspects are important, but do not rise up to the level of requirements to drive reliability performance/outcome. Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on page 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. We suggest the SDT to first determine if the materials in the revised Attachment A (and Attachment B) are “Guideline” or “Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS) (in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM), and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. Further, there are no measures developed for the requirements stipulated/imbedded in Attachment A so how can the Responsible Entity (BA, in this case) be assessed for compliance? We suggest the SDT to move those requirements on the BA to the main standard, and turn Attachment A into an appendix describing the calculation process. An appendix is not regarded as a mandatory requirement. Similar comments apply to Attachment B. Finally, the two Attachments are listed in Section F - Associated Documents. This Section is generally used to list reference documents that are NOT standard requirements. We suggest the SDT review and revise this listing depending on its final determination of the status of the two Attachments (or their revisions, where

Organization	Yes or No	Question 6 Comment
		appropriate).
Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments and modified them to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry. As to the use of the term "may" in the attachment, at this time the drafting team is unable to further restrict the language due to the issues surrounding an individual event. As an example, frequency is scheduled at 60 Hz most of the time. However, when viewed on a graph or an EMS screen, it rarely sits at 60.000 for a long period of time, it fluctuates between 59.995 and 60.005. The drafting team is unable to say at this time that an event that starts with frequency at 60.005 is materially different that an event that starts at 59.995. Therefore, the drafting team has attempted to put guidance into the document as to what is pertinent without attempting to be overly restrictive in the selection criteria since there is no support for a restriction at this time. As more experience is gained, the process should be refined. It the refinement is significant enough to require a change to the Attachment A language, the process required to do so would be open to participation of industry and not done without public exposure. **The SDT agrees with your comment about removing the documents from Section F of the proposed standard has made this modification to the standard.**		
Florida Power & Light Company	No	In the table on page2 the asterick references a statement that the 59.7Hz used in Florida is a special protection scheme. This is incorrect. The special protection scheme setting was 59.82Hz and was done away with in 2005 or earlier. The 59.7Hz setting used within the FRCC is based on FRCC TWG studies that require this level of setting to protect the state in the event of a separation and to protect nuclear equipment. FPL supports the use of the C(N-2) critiera. Additionally, the reference to the FERC714 report that is currently in the background data should be made part of attachment A not separated. FPL fully agrees with Table 1The formula used to derive the FRO is inconsistant with the definition used for requirement R5. R5 states that the load is " within the BA's metered boundary". The load used in the formulae is taken from FERC714. The yearly peak demand used in R5 should be the peak

Organization	Yes or No	Question 6 Comment
		monthly load from June, July or August as reported on FERC714 to be compatible with the FRO formula.
Response: The drafting team has removed the reference to the special protection scheme. The drafting team has modified the FRO allocation formula to better explain what is desired. However, the drafting team did not adjust the formula to what is suggested by the commenter.		
NV Energy	No	It is not clear whether the calculation of FRO is to utilize projections of BA load as in Att A, or past data reported in FERC Form 1 as per the Background Document.
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.		
Los Angeles Department of Water and Power	No	LADWP considers the increase in number of events to analyze (now 25) to be excessive. Previous years analyses typically involved 4-6 events; a permanent five-fold increase is not justified. LADWP suggests reducing the baseline number of events from 25 to 12 per year. Analysis of a larger number of events could be requested on a year-by-year basis if conditions warrant, but should not be mandatory for all regions in all years.
Response: The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. Based on the studies, the drafting team believes that a sample size as suggested would be very likely to cause entities to fail inappropriately due to the large amount of noise in the data related to each event. Additionally, there is a desire to ensure that the events picked are not weighted in such a way to cause the measurements to be increased over actual response. The drafting team has attempted to minimize the effort required of the reporting entities by developing the forms needed to calculate the FRM. Finally, the calculation process is being used for more than the previous process, not to mention that the previous process is not clearly defined and therefore not used consistently across the industry.		
JEA Electric	No	On Event Selection Criteria, bullet 2, if 25 events cannot be identified then the ERO

Organization	Yes or No	Question 6 Comment
Compliance/Florida Municipal Power Agency		can go back in time to the previous year. This creates a double jeopardy to R1 of the standard. It also may include irrelevant data if there have been changes from one year to the next in FRO or Bias settings assigned by the ERO. On Frequency Response Obligation, first paragraph states that "Each Interconnection will establish target contingency protection criteria"; however, the Interconnection is not a decision-making body. Does this really mean the ERO will establish FRO for each Interconnection? The single asterisk note for the table on page 2 states: "It is extremely unlikely that an event elsewhere in the Eastern Interconnection would cause the Florida UFLS special protection scheme to “false trip”.", "Special protection scheme" should be stricken from this sentence, Florida has just a regional difference in its UFLS program.
Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events cannot be found in that period. **The drafting team modified the language to clarify that the ERO will set the IFRO.** **This modification was made.**		
Duke Energy	No	On page 3 of the document it states “For a multiple Balancing Authority Interconnection, the Interconnection Frequency Response Obligation is allocated based upon either the Balancing Authority Peak Demand or peak generation”, however, the initial FRO allocation equation shows that the BA allocation is based upon the sum of the Projected BA Peak Load plus installed capacity, times the Interconnection FRO, and divided by the sum of the Projected Interconnection Peak Load plus Interconnection installed capacity. Is the statement in quotes correct, or is the allocation equation correct? In addition, the equation in Attachment A referencing “installed capacity” conflicts with the equation in the BAL-003-1

Organization	Yes or No	Question 6 Comment
		Background Document entitled "Frequency Response Standard Background Document" where "Peak Gen" is used. In summary, is the FRO allocation based upon an equation which a) sums the Projected BA Peak Load plus peak generation, b) sums the Projected BA Peak Load plus installed capacity, or c) uses either Projected BA Peak Load OR peak generation? All three options are currently represented in the documentation. Calculation of the FRO for the Eastern Interconnection: Duke Energy agrees with the criteria suggested for the event to be protected (4500 MW), and at this time also agrees with the "compromise" low limit of 59.6 Hz. However, knowing that another Standard is under development which may require hourly assessment of available "frequency responsive reserves", we are trying to determine what impact the choice of this methodology will have on the amount of frequency responsive reserves the industry will have to maintain - enough to cover frequency swings that only occasionally reach down to perhaps 59.9 Hz as we see on the Interconnection today (essentially the allocated FRO for a 0.1Hz deviation), enough to cover a 4500 MW loss, or whatever we deem appropriate as long as we are compliant to the FRM? We recognize that the Standard Drafting Team cannot answer this question, as the Standard under development is not within the scope of this team, however our comment is meant to illustrate the point that similar to our response to question 8, it should be recognized that elements of this Standard are tightly coupled to other current and potential Standards, and the impacts must be considered by the Industry.
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity. **The drafting team has added a paragraph in the FRM section of Attachment A limiting the amount of Frequency Response for which a BA will be measured for compliance purposes. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.**		

Organization	Yes or No	Question 6 Comment
SERC OC Standards Review Group	No	The definition of Single Event Frequency Response Data (SEFRD) was struck from the draft standard but still appears in Attachment A. Since R1 of the standard references Attachment A, would the definition of SEFRD still be applicable? If the definition is to be totally struck, we don't think the term should be used in Attachment A.
Response: The SEFRD definition was moved to Attachment A. The SEFRD is used on individual events. The median of a BA's SEFRDs will be used to determine its FRM. Therefore, the drafting team believes it is appropriate to use the definition in the Attachment. Since it is not likely to be used outside of the context of this standard, the drafting team is not proposing to place the definition in the NERC Glossary.		
Hydro-Quebec TransEnergie	No	The Event Selection Criteria should be modified for the Quebec Interconnection. In Table 1, the change in frequency (Delta f) used for Quebec's Event Selection Criteria should be 0,3Hz (from point "A" to point "C") and must last for at least 7 seconds so that we don't measure AGC action. In addition, a criterion should be added by saying that events that recovered within the 20-52 second average period for point "B" should be excluded from analysis.
Response: The drafting team has modified Attachment A to address these comments.		
Keen Resources Asia Ltd.	No	The sample pre-selection described in Attachment A, Event Selection, Criteria 2 & 7, violates the fundamental statistical procedure of unbiased sampling. A population is governed by a single "process" which, when stationary, is represented by a fixed probability distribution. In this case the population is several years of events (which are the subject of Frequency Response), not of normal operating control errors which are the subject of CPM control. A sample is governed by a single process that approximates the process governing the population as the sample gets larger, in this case if it includes several years of data. Samples are measured "as they come", no triage/filtering allowed, and they are called "stratified" when their distribution approximates the population distribution. Unlike normal operating errors, samples of events are not evenly distributed over a year. The attempt in criteria 2 & 7 to pre-select only certain events, and not others, in such a way that the selected events

Organization	Yes or No	Question 6 Comment
		occur evenly throughout the year, is papently wrong because it is trying to "fit" events into a process (even distribution over time) that does not govern events, but that instead governs normal operating errors that are the subject of CPM control, not of this Frequency Response standard. In other words, criteria 2 & 7 confuse Frequency Response with CPM, and events with normal operating errors. The result is a false, biased sample which destroys the integrity of this standard. Paragraph 4 on page 5 of the Background Document, on the other hand, provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 & 7 in Attachment A.
Response: The drafting team has discussed this issue several times and believes that issues related to measurement caused by noise in individual events and the need to ensure adequate representation of events throughout the year outweigh the concern to have a "pure" statistical sample. For these reasons the drafting team has not modified the event selection criteria.		
Northeast Power Coordinating Council	No	The SDT has to first determine if the materials in the revised Attachment A & B are "Guideline" or Technical Background", or are they "requirements". If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as written Attachment A is confusing as it describes the ERO's process for supporting the Frequency Response Standard (FRS) (the method and criteria it uses to calculate the frequency bias settings and the FRM), and at the same time the BA's obligations to support this process. The latter requirements should not be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement. Additionally, regarding BAL-003-1- Attachment A 1. Criterion 5 needs to be re-written for clarity. 2. Criterion 7 refers to "cleanest events". A statement of what constitutes a "clean event" is needed to avoid possible controversy in the future.

Organization	Yes or No	Question 6 Comment
		3. The use of 59.6 Hz as the highest UFLS setting is flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or it should be 59.5 Hz without concern for Florida's unique settings. 4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer "alternate FRO protection criteria". The Interconnection should have been an integral part of establishing its obligation. It is stated that the "ERO will confirm" the "alternate FRO protection criteria". Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify. 5. In the formula for determining the Balancing Authority's FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. The background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify. 6. Recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that the sampling interval is that which works the best for each individual interconnection. 7. Attachment A needs to define the point A sampling interval.

Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry.

1. The drafting team believes that Criterion 5 is clear as written. The comment does not provide any guidance as to what needs

Organization	Yes or No	Question 6 Comment
clarification so no change was made. **2. Due to the complicated nature of event evaluation and selection, the drafting team has retained the word "cleanest" in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience in gained, the NERC Resources Subcommittee will attempt to document the process further.** **3. The drafting team has revised the terminology used to explain the frequency levels proposed. There was not a change to the Eastern Interconnection numbers.** **4. An interconnection can recommend a change to the table. As the standards process currently works, that interconnection would need to support its alternative level with data. If the interconnection has a single Regional Reliability Organization, the ERO would typically agree to the alternative assuming it would be more restrictive (in this case a larger response requirement) than the ERO has recommended.** **5. The drafting team has addressed the concerns raised by clarifying that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.** **6. The drafting team has modified Attachment A to address concerns with selection of an event where frequency returns to the A Value level during the measurement period. These events will be excluded from the measurement process for all interconnections.** **7. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.**		
Sacramento Municipal Utility District (SMUD)	No	The standard is unclear as to if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of Frequency Response expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of Frequency Response that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the

Organization	Yes or No	Question 6 Comment
		frequency to drop to less than 59.6 Hz or in the Western Interconnection that causes the frequency to drop to less than 59.5 Hz, or if that event is excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, it is unclear what is expected of the Balancing Authorities.
Response: The drafting team has added a paragraph in the FRM section of Attachment A limiting the amount of Frequency Response for which a BA will be measured for compliance purposes. This translates to a maximum expectation of Frequency Response equal to a Balancing Authority's FRO times the number of .1 Hz shown in Table 2 in Attachment A.		
Western Electricity Coordinating Council	No	There is disagreement between Attachment A and the Background Document. Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, but the Background Document states it will use "historical" Peak Load and Generation. The allocation methodology of FRO among the BAs in the equation on page 3 of Attachment A favors BAs with more load than more installed capacity. Peak load is served but not all installed capacity is always dispatched.
Response: The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.		
Alberta Electric System Operator	No	These documents not only provide additional clarity but also specify additional requirements, such as FRS Form 1 annual reporting by January 10. All the enforceable requirements should be included in the body of the standard. 1. Attachment A uses the terms "delta F (change in frequency)", "arresting frequency (Point C)", "B Value", "A Value". These terms are not properly defined or described in this document as drafted. The AESO suggests adding a description or definitions for

Organization	Yes or No	Question 6 Comment
		clarity in this document. 2. The standard gives 2 sets of values for Interconnection Frequency Response Obligation in Table 2, (1) Base Obligation and (2) the obligation including 25% Safety Margin (which seems to be implied by the "contingency protection criterion"). The Attachment A does not specifiy whether the Base Obligation or the 25% Safety Margin value will be used to allocate the Interconnection FRO to the BAs. Please clarify which value will be used to calculate the BA Frequency Response Obligation (FRO) in the Interconnection FRO allocation formula in Attachment A. 3. The "initial FRO allocation" formula in Attachment A uses Peak Load. The term Peak Load is not used in the standard nor is it a defined term in the NERC Glossary. The standard uses Peak Demand, which is defined in the Glossary Is "Peak Load" synonymous with "Peak Demand"? If so, Peak Demand should be used in the formula instead. Otherwise Peak Load should be clearly defined in this document. 4. Is "Projected" in the FRO allocation formula synonymous with "Forecasted"? If so, Forecasted should be used for consistency. Otherwise "Projected" or the context in which it appears must be defined.
Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry. **1. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.** **2. The drafting team has modified Table 2 to clarify that the bottom number in each column is the Interconnection FRO. The Interconnection FRO will be allocated to the BAs within that interconnection.** **3 and 4. The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed**		

Organization	Yes or No	Question 6 Comment
methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity.		
Great River Energy/ACES Power Marketing Standards Collaborators	No	Under item 3 of the Event Selection Criteria section, the delta F and Point C should be described either in this attachment or the "Frequency Response Standard Background Document". While many in industry may understand what these terms mean, history has a way of getting lost with personnel turnover. Furthermore, this would help ensure that the auditors and industry have a duplicate understanding. In the Frequency Response Obligation section on page 2, several items require more description. Further description of why an N-2 event was chosen for the Contingency Protection Criteria should be provided and which N-2 event was selected so that industry can help validate if the correct MW value was selected. Furthermore, the document should clarify if the Contingency Protection Criteria contains the "safety margin". There is a statement in the paragraph before the table that states it does but then the table lists out a separate 25% "Safety Margin". Thus, it is not clear if the "Safety Margin" is included in the Contingency Protection Criteria value listed in the table or not. "Safety margin" should be changed to "reliability margin". Safety has a specific meaning in the electric industry and its use here is not appropriate. The Base Obligation should be explained. The explanation should include its purpose and origin.
Response: 1. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets. The drafting team has clarified Table 2 by modifying the titles for each line.		
Texas Reliability Entity	No	We have a number of concerns regarding Attachment A which are set forth below: 1. Regarding the formula for "Initial FRO Allocation" on page 3 of Attachment A, the terms for "BA installed capacity" and "Interconnection installed capacity" are undefined and could be subject to manipulation and dispute. We suggest that this formula be revised to mirror the calculation based on well-established FERC Form 714 data that is discussed in the Background document, which is based on actual

Organization	Yes or No	Question 6 Comment
		generation output. 2. In Attachment A, all references to "Texas" should be changed to "ERCOT" as a reference to the Interconnection or the Region (including tables). 3. Regarding the Event Selection Criteria in Attachment A: in item 2, consider whether certain events, such as DCS events, should be required to be included in the FRM analysis. 4. Regarding the Event Selection Criteria in Attachment A: item 7 provides that the selected frequency excursion events are to be selected so that they are evenly distributed seasonally. Consider adding the seasonal distribution concept to item 2, particularly if it becomes necessary to include events from the previous evaluation period. 5. In Attachment A, page 1 says the ERO is to post the final list of frequency excursion events by December 15, but on page 3 it suggests that the list will be posted by December 10. These references should be made consistent. 6. Attachment A states, on page 3, "the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year: Frequency Bias Setting and Frequency Response Obligation (FRO)." What is meant by "the upcoming year"? Is the BA supposed to implement the new FBS immediately, or wait until the beginning of the next evaluation period on December 1? Note that if the new FRO and FBS are implemented immediately (e.g. in March), then the FRO will change in the middle of an evaluation period. This will complicate the comparison of FRM and FRO as required by R1.
Response: 1. The drafting team has addressed the discrepancy between the two documents to ensure that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity. **2. This change was made.**		

Organization	Yes or No	Question 6 Comment
3. The drafting team recommends all events with a frequency deviation that meets the selection criteria should be evaluated. For the entity that lost generation (or load) to initiate the event, the calculation methodology proposed allows adjustments to be made for that event. 4. This modification was made to the Attachment B (now a Procedure). The suggested modifications are shown in Criteria 2 and 7. 5. These two documents have been conformed. 6. The ERO will notify the BAs as to the date the Frequency Bias Setting is to be implemented if they are utilizing a fixed Frequency Bias Setting.		
Southern Company	No	We suggest increasing the delta f for the East to be the same value as the West or larger. The reason for this is that the 0.04Hz suggested is too close to the governor deadbands of .036Hz. This would potentially omit frequency response that some units may provide for a larger excursion but not for those close to the deadband.
Response: The delta f values have been selected to balance the need to have a sufficient number of events for evaluation and the need to have sufficient frequency movement to actually measure response. At this time the drafting team is not modifying the eastern interconnection values based on the event selection process for the period December 2010 through November 2011.		
ISO New England Inc	No	We suggest the SDT to first determine if the materials in the revised Attachment A & B are “Guideline” or Technical Background”, or are they “requirements”. If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO’s process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA’s obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the proposed method. An appendix is not regarded as a mandatory requirement. Additionally, BAL-003-1- Attachment A

Organization	Yes or No	Question 6 Comment
		1. Criterion 5 needs to be re-written for clarity. 2. Criterion 7 refers to the "cleanest events". Perhaps a statement of what constitutes a "clean event" is needed to avoid possible controversy in the future. 3. The use of 59.6 Hz as the highest UFLS setting seems flawed. It should either be 59.7 Hz as a deliberate choice to protect Florida interests, or, it should be 59.5 Hz without concern for Florida's unique settings. 4. In the last 2 sentences at the end of the section on Frequency Response Obligation, it refers to an Interconnection being able to offer "alternate FRO protection criteria". It seems that the Interconnection should have been an integral part of establishing its obligation. Also, it states that the "ERO will confirm" the "alternate FRO protection criteria". Does this mean the ERO unconditionally approves it, or evaluates with a right of rejection? Please clarify. 5. In the formula for determining the Balancing Authority's FRO allocation, installed capacity is used. Does the industry have a clear and consistent definition for installed capacity? Also, with greater wind energy development, the delivered capacity over longer time horizons will be substantially less than nameplate machine ratings. Also, the background document refers to the use of peak generation instead of installed capacity. Which shall be used? Please clarify. 6. Very recent studies have shown that the 18-52 second sampling interval does not work well for the Quebec Interconnection, in part due to the excellent and high level of response found in that Interconnection. The standard needs to be modified such that the sampling interval is that which works the best for each individual interconnection. 7. Attachment A needs to define the point A sampling interval.

Response: The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the

Organization	Yes or No	Question 6 Comment
process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry. 1. The drafting team believes that Criterion 5 is clear as written. The comment does not provide any guidance as to what needs clarification so no change was made. 2. Due to the complicated nature of event evaluation and selection, the drafting team has retained the word cleanest in the document without providing further clarification or definition. The drafting team believes that the process being developed by NERC (specifically the NERC Resources Subcommittee and the Frequency Working Group) requires some leeway. As more experience in gained, the NERC Resources Subcommittee will attempt to document the process further. 3. The drafting team has revised the terminology used to explain the frequency levels proposed. There was not a change to the Eastern Interconnection numbers. 4. An interconnection can recommend a change to the table. As the standards process currently works, that interconnection would need to support its alternative level with data. If the interconnection has a single Regional Reliability Organization, the ERO would typically agree to the alternative assuming it would be more restrictive (in this case a larger response requirement) than the ERO has recommended. 5. The drafting team has addressed the concerns raised by clarifying that historical data is used for the allocation of an Interconnection Frequency Response Obligation to the BAs within that interconnection. Installed capacity is not used in the allocation methodology. The proposed methodology uses the average of the historical peak loads (monthly peak) and peak generation (monthly peak) and does not use installed capacity. 6. The drafting team has modified Attachment A to address concerns with selection of an event where frequency returns to the A Value level during the measurement period. These events will be excluded from the measurement process for all interconnections. 7. The definition of the terms are provided in the background document as well as the formulas in the spreadsheets.		
Constellation Energy Commodities Group	Yes	Additional information relating to defining the FRO for the Interconnection would be helpful as would an example for calculating the BA FRO.
Response: The drafting team has revised Attachment A to provide better explanation and to clarify the allocation methodology to		

Organization	Yes or No	Question 6 Comment
the BA.		
American Electric Power	Yes	A frequency response observation should not be used spanning multiple years, or if there does, there should at least be a reset period.
Response: The drafting team has discussed the concern of double jeopardy several times. At this time, the drafting team believes the issue of noise in individual events and the convergence of measurement of multiple events outweighs the double jeopardy concerns. After further discussions, the drafting team has reduced the minimum number of events in a 12 month period to 20 from 25 but is still recommending that events from a previous year be used for the calculation if this number of events cannot be found in that period.		
Cleco Corporation/ SPP Standards Review Group	Yes	We appreciate the effort of the SDT in developing Attachment A. It was very helpful in weeding through BAL-003.
Response: Thank you for your comments.		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Associated Electric Cooperative Inc	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 6 Comment
Ameren	Yes	

7. The second document "BAL-003-1 Background Document" provides information behind the development of the standard. Do you agree that this new document provides sufficient clarity as to the development of the standard? If not, please explain in the comment area.

Summary Consideration: The majority of the commenters referenced other questions in the comments. The SDT asked them to review the response to those earlier questions.

Several of the commenters pointed out that there was a discrepancy between the Background Document and Attachment A regarding the calculation of the BA FRO. The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Some commenters indicated that Supplemental Regulation Service is not an appropriate method to provide Frequency Response. It is inappropriate to expect supplementary regulation to transfer frequency response successfully. However the SDT does not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as in all events across the measurement period.

Organization	Yes or No	Question 7 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that the document "BAL-003-1 Background Document" seems to be reasonable.
Response: Thank you for your comment.		
Energy Mark, Inc.	No	Comment 14: Some of the information in this document concerning the Frequency Bias Setting for BAs participating in Overlap Regulation should be moved to the Supporting Document. This change would help in addressing Comments 3 & 4 under Question 2.
Response: The SDT has added language to Attachment A to address your concern.		

Organization	Yes or No	Question 7 Comment
Duke Energy	No	Please see our comments to Question 6. In addition, Duke Energy disagrees with the statement on page 9 that Attachment B will “ensure there is no negative impact on other Standards” - please see our response to Question 8 for additional information.
Response: Thank you for your comments. Please see the responses to Questions #6 and #8.		
SERC OC Standards Review Group	No	Portions of the Background Document do not appear to be complete or finished. The Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. elimination of the definition of SEFRD and any revisions to the draft BAL-003-1).
Response: The SDT has made significant modifications to the Background Document to support the proposed standard. The SDT is proposing that this document be posted on the NERC web site in order for it to be easily obtained by stakeholders once the standard is approved.		
ERCOT	No	Refer to comments in #1.
Response: Refer to the response in Question #1.		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6.For the Frequency Response Standard Background Document – 1. Cite Attachment B in addition to Attachment A in the discussion of requirement R1. 2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A. 3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12. 4. On page 6, drop the inappropriate recommendation of getting frequency response

Organization	Yes or No	Question 7 Comment
		through supplemental regulation. It is inappropriate to try to substitute a "minute plus" product that is deployed centrally by the Balancing Authority for a "sub-minute" product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it. This comment also applies to the mentioning of supplemental regulation on page 11 as well. 5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the standard. The standard states that any time within the designated date is acceptable. 6. On page 8, the inclusion of "for training purposes" as a reason to not operate in tie line bias control should be dropped. This training can be done in a training simulator. If it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly. 7. On page 14, the sentence: "This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations" is difficult to understand. The paragraph would read better by simply deleting the sentence.

Response: Please refer to our response to Question #6.

Comment 1 – The SDT has modified the Background Document to incorporate your suggested change.

Comment 2 – The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Comment 3 – The SDT has removed the speculative language and replaced it with more appropriate language.

Comment 4 - While the SDT agrees that it is inappropriate to expect supplementary regulation to transfer frequency response

Organization	Yes or No	Question 7 Comment
successfully, we do not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as all events across the measurement period. Comment 5 – The SDT has corrected the background document to accurately reflect the language proposed in the standard. Comment 6 – The SDT has modified the background document to remove the training language. Comment 7 – The SDT has revised the paragraph to provide additional clarity.		
Xcel Energy	No	Same comment here as the one in question 6.
Response: Please refer to our response to Question #6.		
ISO New England Inc	No	See first comment in 6 above. Also, Frequency Response Standard Background Document – 1. Cite Attachment B in addition to Attachment A in the discussion of requirement 1. 2. The Balancing Authority allocation method specified in this document does not agree with that in Attachment A. 3. Drop the speculation on page 4 that most Balancing Authorities will be compliant. While it may be a commonly held belief by many that there is adequate frequency response right now, that assessment should be made after a targeted level of reliability has been defined and approved. The same comment applies on page 12. 4. On page 6, drop the inappropriate recommendation of getting frequency response through supplemental regulation. It is inappropriate to try to substitute a "minute plus" product that is deployed centrally by the Balancing Authority for a "sub-minute" product that is deployed automatically without any Balancing Authority action. When a pseudo-tie is used, changes in the ACE values due to supplemental regulation are unrelated to and not coordinated with the need to deploy frequency response. Not only should this approach not be offered as an alternative, but the FRSDT should

Organization	Yes or No	Question 7 Comment
		actively conduct research to determine if supplemental regulation via a pseudo-tie should be deliberately REMOVED from any actual net interchange calculation that may include it! This comment also applies to the mentioning of supplemental regulation on page 11 as well. 5. On page 7, the reference to a 24 hour window on each side of the frequency bias setting implementation date is inconsistent with the wording of the requirement. The requirement says that any time within the designated date is acceptable. 6. On page 8, the inclusion of "for training purposes" as a reason to not operate in tie line bias control should be dropped. This sort of training can be done in a training simulator. Alternatively, if it is determined that it should be supported, then the requirement needs to be reworded to allow it explicitly. 7. On page 14, the sentence: "This approach would only provide feedback for performance during that specific event and would not provide insight into the depth of response or other limitations" is difficult to understand. The paragraph would read better by simply dropping it.

Response: Please refer to our response to Question #6.

Comment 1 – The SDT has modified the Background Document to incorporate your suggested change.

Comment 2 – The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Comment 3 – The SDT has removed the speculative language and replaced it with more appropriate language.

Comment 4 - While the SDT agrees that it is inappropriate to expect supplementary regulation to transfer frequency response successfully, we do not want to prevent any innovative solution that will transfer frequency response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging supplementary regulation via a pseudo-tie have to be consistent in the removal or inclusion of it in their actual net interchange measurement as well as all events across the measurement period.

Comment 5 – The SDT has corrected the background document to accurately reflect the language proposed in the standard.

Organization	Yes or No	Question 7 Comment
Comment 6 – The SDT has modified the background document to remove the training language. **Comment 7 – The SDT has revised the paragraph to provide additional clarity.**		
Western Electricity Coordinating Council	No	See response to question 6.
Response: Please refer to our response to Question #6.		
Alberta Electric System Operator	No	The Background Document uses BA Peak Generation in the BA FRO allocation formula. Attachment A uses BA Installed Capacity. The AESO suggests making the two formulae consistent.
Response: The drafting team has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.		
Florida Municipal Power Agency	No	The document does not discuss how the new reliability parameter will affect BAs
Response: The new standard will require that Balancing Authorities meet a level of response to frequency events equal to or more negative than their Frequency Response Obligation. The SDT has made significant modifications to the Background Document which should address your concern.		
JEA Electric Compliance	No	The document does not discuss how the new reliability parameter will affect BAs
Response: The new standard will require that Balancing Authorities meet a level of response to frequency events equal to or more negative than their Frequency Response Obligation. The SDT has made significant modifications to the Background Document which should address your concern.		
MRO NSRF	No	The MRO NSRF has restated the same answer as in question 6 on purpose. Confusion exists around the “peak load” in that Attachment A states the allocation is based on Projected Peak Loads and Generation but the Background Document states it will use

Organization	Yes or No	Question 7 Comment
		a historical Peak and Generation to make the allocation. Also, for the BA installed capacity, where is that value derived from and does NERC obtain that from FERC form data or does the BA provide that information somewhere specific to this effort? Additionally, there appears to be a difference in how FRO is calculated in Attachment A and what is described in the Background Document. These differences should be reconciled such that both documents address the same approach. If installed capacity is used in the equation, how are variable/intermittent resources (e.g. wind, solar) accounted for? At full capacity? Please clarify. Page 7 (3rd paragraph) of the Background document states "Given the fact that BA's can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date. 1) The Standard itself does not state this provision (24 hour window on each side of target date) as indicated. 2) The SDT accurately addresses the fact that BA's could have EMS or staffing issues during implementation of the ERO validated FBS. The current stated 72-hour window is not long enough for implementation of the FBS as there may be a host of issues that could impact implementation. We suggest that a seven day window be used for implementation of the FBS.
Response: The drafting team has corrected the proposed standard to accurately reflect the language in the Background Document.		
Texas Reliability Entity	No	There is an inconsistency between the Background Document and Attachment A. Attachment A only proposes event criteria based on "the largest category C (N-2) event identified," but the Background Document says: "Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation: - Largest category C loss-of-resource (N-2) event; - Largest total generating plant with common voltage switchyard; - Largest loss of generation in the interconnection in the last 10 years."

Organization	Yes or No	Question 7 Comment
Response: The drafting team has corrected the reference so both documents agree.		
Great River Energy/ACES Power Marketing Standards Collaborators	No	We can find no document titled “BAL-003-1 Background Document”. We assume this question is referring to the “Frequency Response Standard Background Document” dated October 2011. We do not believe the document provides sufficient clarity. No explanation is provided for why RSG was added to Requirement R1.There are typos contained in the document. On page 6 in NIA, the A should be in subscript. On page 7 in bullet 4 in the first sentence, “The” should be in lowercase
Response: Your assumption was correct. The drafting team has corrected these typos.		
Southern Company	No	We suggest the Background Document should be edited to be consistent with changes made to the standard or other related documents (eg. Any revisions to draft BAL-003-1 and removal of the definition of SEFRD).
Response: Thank you for your comments. The drafting team revised the background document based upon modifications to the standard as well as modifications to other documents related to the standard.		
Seattle City Light	Yes	o LADWP and SCL note that the document “BAL-003-1 Background Document” seems to be reasonable.
Response: Thank you for your comments.		
Constellation Energy Commodities Group	Yes	Should be revisited based on the propposed modifications to the requirements.
Response: Thank you for your comments. The drafting team revised the background document based upon modifications to the standard as well as modifications to other documents related to the standard.		
Los Angeles Department of Water and Power	Yes	LADWP notes that the document “BAL-003-1 Background Document” seems to be reasonable.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments.		
Keen Resources Asia Ltd.	Yes	Paragraph 4 on page 5 of the Background Document provides a statistically correct description of event selection without sample pre-selection and should followed instead of the erroneous criteria 2 & 7 in Attachment A. The risk-based approach to determining FRM, that the Background Document mentions in paragraph 4 of page 4 is being evaluated by the drafting team for application in this standard, should be considered for deployment as soon as possible to replace the administered method currently proposed in this standard, because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.
Response: The standard has to be written with what will be used day one. Due to the timeline that NERC has filed with FERC, there is not enough time to adequately evaluate a second methodology.		
Manitoba Hydro	Yes	Please see MH’s response to Question 1 regarding the term Single Event Frequency Response Data. Additionally, the discussion in this document is useful in clarifying the intent of the drafting team, but some of this clarification would best be incorporated into the Standard itself. Ex. RSG requirement on page 6. Also on page 7 Attachment A does not specify what validation is and how it is done. Attachment A refers to BA providing FBS data to ERO which then validates and publishes. This should be reflected in R2.
Response: Please refer to our response to Question 1. **The “validation” process is nothing new. The ERO presently validates the information sent in by BAs today. The ERO will not be**		

Organization	Yes or No	Question 7 Comment
performing this process in a vacuum, but will be working with the BAs in the same manner as they presently do.		
NV Energy	Yes	This is a good reference; however see response to Question 6 in that there appears to be a discprepancy between Att A and the Background Document with regard to FRO calculation.
Response: The drafting team has corrected the discrepancy so both documents now agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.		
Cleco Corporation/SPP Standards Review Group	Yes	We appreciate the effort of the SDT in developing the Background Document. It provided insight on how the SDT got the proposed standard to where it is with this posting.
Response: Thank you for your comment.		
Imperial Irrigation District	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Florida Power & Light Company	Yes	
FPL	Yes	
FMPP	Yes	

Organization	Yes or No	Question 7 Comment
Tucson Electric Power	Yes	
Associated Electric Cooperative Inc	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
ISO/RTO Council Standards Review Committee/ Independent Electricity System Operator		We do not have an opinion on whether or not the Background Document provides sufficient clarity to the development of the standard. We do, however, suggest that the SDT consider our comments in Q6, above, and move some of the information from Attachments A and B to or combine with the Background Document, to the Background Document to provide all the technical basis and background behind the elements stipulated in the requirements.
Response: Please refer to our response to Question #6.		

8. **The SDT has developed a new document titled Attachment B – Process for Adjusting Bias Setting Floor. This document is intended to provide the methodology the ERO will use to reduce the minimum Frequency Bias Setting to become closer to natural Frequency Response. Do you agree that this document provides clear and concise instructions for the ERO to follow? If not, please explain in the comment area.**

Summary Consideration: The majority of commenters did not like the word "initially" that was used in the proposed standard. They felt that it caused confusion. The SDT modified the attachment to remove the reference to the word "initially" and added other clarifying language to the document.

Some commenters were concerned with how the calculation of FRO for BAs that have load and generation. The intent was that generation-only BAs would base their settings on generation. Traditional BAs would use load. The SDT revised the table to agree with the proposed standard.

One commenter indicated that the standard was measuring AGC. The SDT disagrees.. There may be some AGC influence in the measurement however the SDT believes that this impact is minor. Based on the data received from the Field Trial, the SDT did not see this phenomenon.

A couple of commenters indicated that the methodology used for calculation of the minimum Frequency Bias Setting could be adverse for a single BA interconnection. The SDT explained that to ensure comparable treatment between BAs with fixed Bias Settings, BAs with a variable Bias Setting report their monthly average Bias for the reporting year. This average will be calculated when frequency is greater than 60.036 Hz or less than 59.964 Hz. The average of the 12 months' Bias values must be equal to or more negative than the Interconnection's minimum Bias Setting.

Organization	Yes or No	Question 8 Comment
Seattle City Light	Negative	Answer: Yes Comments: o LADWP and SCL note that Attachment B seems to be reasonable.
Response: Thank you for your comment.		
Constellation Energy Commodities Group	No	Should be revisited based on the proposed modifications to the requirements.

Organization	Yes or No	Question 8 Comment
Response: The SDT has modified Attachment B, now a Procedure for the ERO to follow in supporting the standard, to reflect modifications to the requirements and suggested changes from the industry.		
MRO NSRF	No	: There could be some confusion caused by the Attachment B due to the use of the word “initially” when the reference is made to the current standard. The drafting team should change the word “initially” to “currently” or strike it to avoid the potential confusion. The second paragraph of Attachment B (which contains the two bullets):The words “initially 1%” in the second bullet contradict with the Table 1 on Attachment B, which states “Initial” and “0.8%”. Suggest deleting the parenthetical in the second bullet as when BAL-003-1 is effective it would be referencing an old Standard version. If the initial minimum is intended to be 1% say so in the Table 1.
Response: The SDT has modified Attachment B, now a Procedure for the ERO to follow in supporting the standard, to reflect your suggested changes.		
Texas Reliability Entity	No	1. In Attachment B, we suggest removing the paragraph beginning “The BA calculates . . .” because it appears to be background information that conflicts with the methods provided in this version of the standard for determining minimum bias settings.2. 2. Attachment B, Table 1, refers to “0.8% of peak load or generation.” If a BA has both load and generation, will its minimum Frequency Bias Setting be based on its load, its generation, or can it pick the value that it prefers to use?
Response: The SDT agrees and has removed it from the Attachment B, now a Procedure. **The SDT intended that generation-only BAs would base their settings on generation. Traditional BAs would use load. We have revised the table to agree with the proposed standard.**		
Bonneville Power	No	BPA understands the concept and we disagree with it. As the ERO continues to lower the required minimum frequency bias setting for an interconnection, the BA’s that

Organization	Yes or No	Question 8 Comment
Administration		have frequency response higher than the 1% will have a higher percentage of the frequency response of the interconnection. Also, this standard is primarily measuring AGC response, not natural frequency response; therefore not lowering the limit is appropriate.
Response: The SDT believes that you may be mixing the Frequency Bias Setting and Frequency Response Measure. As proposed the FRO will be assigned based upon load and generation as defined in Attachment A. Therefore actual Frequency Response will be required to come from the interconnection on that basis. To the extent an entity has a FRM greater than its Interconnection's minimum Frequency Bias Setting, its Frequency Bias Setting may grow as a percent of the Interconnections total Frequency Bias Setting. However, that is not Frequency Response. **The SDT disagrees with your comment concerning AGC. There may be some AGC influence in the measurement however the SDT believes that this impact is minor. Based on the data received from the Field Trial, the SDT did not see this phenomenon.**		
Duke Energy	No	Duke Energy suggests that the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1. Notwithstanding our suggestion that the criteria/requirements of the minimum FBS in the Attachment be incorporated into the Standard, Duke Energy has the following concerns with what is proposed: As cited in our comments to Question 8 in the last posting (extensive, so not repeated here), the secondary control measures of CPS1, CPS2 and the draft Balancing Authority ACE Limit (BAAL) are tightly coupled to the Frequency Bias Setting (FBS), and a reduction of the FBS will impact the secondary control requirements placed upon the BA. Noted in our response to Question 7 above, the statement on page 9 in the "BAL-003-1 Background Document"is not correct in stating that Attachment B will "ensure there is no negative impact on other Standards".The gradual reduction of the FBS will proportionally tighten the secondary control limits for each Balancing Authority. Even if the "natural" Frequency Response in the Eastern Interconnection remains unchanged for the next several years, under the process described allowing the ERO to annually adjust the minimum FBS for the Interconnection, the FBS will

Organization	Yes or No	Question 8 Comment
		eventually be reduced to a value approximately 10% above the calculated response in magnitude, cutting the current CPS1, CPS2 and BAAL limits in the Eastern Interconnection on average by more than half. The current FBS for the Eastern Interconnection is approximately minus 6500 MW/0.1Hz, estimated “natural” Frequency Response is perhaps around minus 2400 MW/0.1Hz. Unlike CPS1 and BAAL where the measures are based upon the FBS of the BA only, CPS2 (dependent upon the FBS of the BA and the Interconnection) will be significantly limiting to the degree that no change in a BA’s own Frequency Response could significantly change its CPS2 limit if the Interconnection FBS drops over time as indicated. At least under CPS1 and the draft BAAL, the BA would have an option of improving its Frequency Response, allowing it to increase its FBS and proportionally the CPS1 and BAAL bounds using the FBS. Conclusion from our last comments submitted: Duke Energy does not believe there is a reliability need pushing the industry to tighten secondary control to the degree discussed above simply as a result of reducing the Frequency Bias Setting. If the calculated Frequency Response of the Interconnection stayed at its current level, what would be the justification for tightening the secondary control requirements of CPS1, CPS2 and the proposed BAAL? Duke Energy supports taking more of the error out of the ACE equation by having the FBS closer to the estimated Frequency Response of the Balancing Authority, however, Duke Energy does not believe the result should be a significant increase in secondary control costs to meet the CPS1, CPS2, or draft BAAL requirements. Duke Energy understands the position placed upon this Standard Drafting Team- the secondary control and reserve requirements are not under the scope of the team, however, proper consideration has not been given in Attachment B to the impact lowering the FBS will have on the industry in terms of the requirements placed upon the BA for secondary control and reserve requirements - especially for meeting CPS2. The research discussed in our comments to the last posting support that reducing the FBS while under CPS1 and the draft BAAL may be achievable, however a CPS2 bound cut potentially in half or lower will place unreasonable bounds on a BA, requiring control actions even when the BA may

Organization	Yes or No	Question 8 Comment
		be operating in support of the Interconnection frequency. Given the significant impacts discussed, Duke Energy believes that additional provisions must be in place for the Industry to approve each subsequent revision to the calculation of the minimum Frequency Bias Setting, rather than leave it as a decision made only by the ERO.

Response: We agree with your comment about the word "initial" in Attachment B, now a Procedure for the ERO to follow in supporting the standard, and have removed the word "initial" from the title to remove the confusion.

We believe that your assessments about the effects on CPS2, BAAL and CPS1 are uncertain because there are complex interactions between the Frequency Bias Setting and the ACE values in these measures that use a Frequency Bias Setting.

We agree that the words in Attachment B, now a Procedure for the ERO to follow in supporting the standard, stating "ensure there is no negative impact on other standards" is an overstatement at this point. We have added language to allow for analysis prior to implementing changes to the minimum Frequency Bias Setting. This is also why we have chosen to go slow with the concept of allowing the frequency bias setting to be reduced below 1% of Peak Load.

We agree with your support of taking more of the error out of the ACE equation by making the FBS closer to the estimated Frequency Response of the Balancing Authority; however, we do not agree that the effects of secondary control can be ignored when we make these changes. Therefore we are proposing a "go slow approach" to making this happen and included checks to confirm there are not unexpected influences injected into the CPS-related calculations.

Based on concerns raised by the industry, the drafting team has modified the Attachment B, now a Procedure for the ERO to follow in supporting the standard, to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

We support your comment related to the ERO working with the Industry to approve each subsequent revision to the minimum FBS. However, it is this drafting team's understanding that the language in the standard is limited to referencing the ERO and the ERO will develop a process to address the needs of the standard. Therefore, no modification has been made to require any specific coordination between the ERO and the Industry.

Organization	Yes or No	Question 8 Comment
Sacramento Municipal Utility District (SMUD)	No	In addition to the requirements, reducing frequency bias obligation results in generation tripping closer to the set point. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response: The SDT is unsure of what your first comment is attempting to say. Therefore the SDT cannot provide a response to your comment without further clarification. **The SDT believes that you may be mixing the Frequency Bias Setting and Frequency Response Measure. As proposed the FRO will be assigned based upon load and generation as defined in Attachment A. Therefore actual Frequency Response will be required to come from the Interconnection on that basis. To the extent an entity has an FRM greater than its Interconnection's minimum Frequency Bias Setting, its Frequency Bias Setting may grow as a percent of the Interconnection's total Frequency Bias Setting. However, that is not Frequency Response.**		
NV Energy	No	In Attachment B, it seems unclear whether the initial FB setting is supposed to be 1% of BA peak load or 0.8% as shown in the table. In general, I was extremely confused about what the required FB setting should be. R5 indicates a percentage of load found in Att B, but Att B indicates the greater of Natural Frequency Response or 1% of peak, and then the table that follows indicates 0.8%. At this point, I have no idea what is being stated for the requirement.
Response: The SDT agrees and has modified the attachment. **The SDT intended that generation-only BAs would base their settings on generation. Traditional BAs would use load. We have revised the table to agree with the proposed standard.**		
Progress Energy	No	PGN supports the collective comments of SERC members. We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1

Organization	Yes or No	Question 8 Comment
Response: The SDT agrees with your comments and has made corresponding modifications to the attachment by removing the word, “initial”.		
Independent Electricity System Operator	No	Please see our comments under Q6. In brief, we do not agree with including a process description type of document as part of the standard requirement.
Response: Please refer to our response to Question #6.		
ISO/RTO Council Standards Review Committee	No	Please see our comments under Q6. In brief, we do not agree with including a process description type of document as part of the standard requirement. Process description should be regarded guideline document and not a part of the standard requirement.
Response: Please refer to our response to Question #6.		
Tucson Electric Power	No	Reducing a BAs frequency bias setting may have an adverse impact on recovering from a frequency event once you get past the first 8-10 seconds. A larger bias will allow for actual and sustained AGC generator responses. Industry focus should be on generator governor response within the first 8-10 seconds.
Response: The Standard Drafting Team disagrees with your comment. Full recovery is dependent upon the contingent BA recovering from its loss. However, we do agree that secondary frequency support from the non-contingent BAs may not be as robust.		
Northeast Power Coordinating Council	No	Refer to the first comment in Question 6.
Response: Please refer to our response to Question #6.		
Hydro-Quebec TransEnergie	No	The methodology proposed to compute the Minimum Frequency Bias Setting (in MW/0,1Hz) could be adverse for the Quebec Interconnection. Hydro-Quebec uses a

Organization	Yes or No	Question 8 Comment
		variable Bias that is calculated based upon which generator is online and it's droop setting. Under light load condition, we might have a Bias setting that would be under (in absolute value) than the FRM which is the median value, even though the Bias setting would reflect the grid's frequency response. This method, as proposed, would mandate us to have a larger Bias that what is really needed. Unlike Eastern Interconnection, we are not over biased. By implementing this new methodology, it would make us over biased. Having a too large Bias could lead to system instability, based on the results of studies from our control specialists. The Minimum Frequency Bias Setting should take into account the wide load span that we can face. For the variable bias, we could express the Minimum Frequency Bias Setting as a function of monthly peak loads, and remove the Natural Frequency Response term. In addition, there is a gap between Attachment B and the text in R5. See comment 10 for explanation.
Response: To ensure comparable treatment between BAs with fixed Bias Settings, BAs with a variable Bias Setting report their monthly average Bias for the reporting year. This average will be calculated when frequency is greater than 60.036 Hz or less than 59.964 Hz. The average of the 12 months' Bias values must be equal to or more negative than the Interconnection's minimum Bias Setting.		
Xcel Energy	No	There could be some confusion caused by the Attachment B due to the use of the word "initially" when the reference is made to the current standard. The drafting team should change the word "initially" to "currently" or strike it to avoid the potential confusion.
Response: The SDT agrees with your comment and has modified the attachment to remove the word, "initially".		
Florida Power & Light Company	No	There is no technical justification provided either in the attachment or background data for the initial starting value of 0.8%. This is acceptable but is arbitary. Additionally, the last sentense on page 1 of Attachment B should be changed to read " the ERO must reduce (in absolute value) the minimum Frequency Bias Settings for BA's within that Interconnection, by 0.1 percentage point from its previous annual

Organization	Yes or No	Question 8 Comment
		value, to better match the Frequency Bias Setting to the natural Frequency Response or provide technical justification for not implementing the reduction
Response: You are correct, the starting value is arbitrary. The SDT did not want to make a one step change to immediately reduce the minimum Frequency Bias Setting to natural Frequency Response. The SDT believes that a multi-year multi-step process would be better and allows for monitoring the effects on other performance standards. The SDT believes that the end result would be the same. The present wording allows for collaboration between the ERO and other entities/groups. The SDT is also concerned with putting a requirement on the ERO within an Attachment when there is not a reliability problem if it were not to happen.		
SERC OC Standards Review Group	No	We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1
Response: The SDT agrees with your comment and has modified the attachment by removing the word, "initial".		
South Carolina Electric and Gas	No	We suggest the SDT consider a term other than "Initial' in the title for Table 1. We suggest "Proposed Frequency Bias Setting" for Table 1
Response: The SDT agrees with your comment and has modified the attachment by removing the word, "initial".		
ISO New England Inc	No	We suggest the SDT to first determine if the materials in the revised Attachment A & B are "Guideline" or Technical Background", or are they "requirements". If it is the former, then Requirement R1 should not mention Attachment A at all. If it is the latter, then the as-written Attachment A is a mix bag as it on the one hand describes the ERO's process for supporting the Frequency Response Standard (FRS), in other words, the method and criteria it uses to calculate the frequency bias settings and the FRM, and on the other hand the BA's obligations to support this process. We strongly disagree that the latter requirements be imbedded in an attachment, especially one that is supposed to provide the technical background and guideline for another entity which, by the way, is not held responsible for complying with the

Organization	Yes or No	Question 8 Comment
		proposed method. An appendix is not regarded as a mandatory requirement.
Response: The process is still being developed at NERC but an Attachment would document processes to be utilized without a measurement saying that you failed the standard.		
Southern Company	No	We suggest using the words, 'Proposed Frequency Bias Setting' in the Title of Table 1 instead of the word, 'Initial'.
Response: The SDT agrees with your comment and has modified the attachment by removing the word, "initial".		
ERCOT	No	While there is no problem with the calculation involved, it is unclear why the SDT elected to assign a grid performance element in this standard to the ERO, who has no functional (registered) role in grid performance. Since this is a cook-book calculation and transfer of data on frequency performance, why not assign it to the BA?
Response: The Attachment B, now a Procedure for the ERO to follow in supporting the standard, only outlines a process that the ERO is to use when adjusting the minimum Frequency Bias Setting. The Procedure does not place any grid performance requirement on the ERO. The SDT also believes that some authority should have oversight over the minimum setting to prevent abuses and assure fairness.		
Seattle City Light	Yes	o LADWP and SCL note that Attachment B seems to be reasonable.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Energy Mark, Inc.	Yes	Comment 15: This Yes answer assumes that the SDT addresses Comment 13 under Question 6 in these comments.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT addressed your Comment #13 under Question #6.		
Ameren	Yes	Considering the comments made regarding R5, in question 2, above, which are:

Organization	Yes or No	Question 8 Comment
		R5. While we agree with the requirement of R5, it should not be at the expense of changing the value of L10 in BAL-001, R2, which has been accepted by FERC in Order 693. An accommodation should be made so that any changes to the Frequency Bias Setting according to BAL-003, R5, should not affect the value of L10 used in BAL-001, R2.
Response: The SDT thanks you for your affirmative response and clarifying comment. However, the SDT disagrees with your comment. Since L_{10} is the function of individual Frequency Bias Settings to the sum of all BA Frequency Bias Settings within an Interconnection and establishes operating boundaries, it would be inappropriate to leave L_{10} as is when a Frequency Bias Setting changes.		
Los Angeles Department of Water and Power	Yes	LADWP notes that Attachment B seems to be reasonable
Response: The SDT thanks you for your affirmative response and clarifying comment.		
FPL	Yes	Last paragraph: As stated, would that make the Minimum Frequency Bias Setting 0.7% of peak load or generation? A numerical example shown would help clarify this paragraph.
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT has added an example to the Background Document.		
Southwest Power Pool Regional Entity	Yes	Need to clarify that 2012 Bias setting will be based on 1% of peak load or generation until approval of BAL-003-1 by FERC establishing the .08% of peak load or generation minimum threshold.
Response: We agree and we have endeavored to do so. The SDT does point out that the proposed minimum for the first year once approved by FERC is 0.9% not 0.08%.		
Associated Electric	Yes	This is a very important document, providing bounds and rationale for and future

Organization	Yes or No	Question 8 Comment
Cooperative Inc		changes, as well as initial settings going into ballot. As such, it is AECI's understanding that, upon going into effect, this BAL-003-1 will utilize these initial settings.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
Imperial Irrigation District	Yes	
SPP Standards Review Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Salt River Project	Yes	
FMPP	Yes	
American Electric Power	Yes	
Cleco Corporation	Yes	
Manitoba Hydro	Yes	
Great River Energy	Yes	
Keen Resources Asia Ltd.	Yes	

9. **The SDT has provided an additional spreadsheet, FRS Form 2, to assist the Balancing Authority in providing the data needed to comply with the proposed standard. Do you agree that this spreadsheet is useful and the instructions are meaningful? If not, please explain in the comment area.**

Summary Consideration: Many of the commenters expressed concern with the fact that the Excel Spreadsheets that were required to be used were in a newer version of Excel than their company was presently using. In response, the SDT developed Excel Spreadsheets that are compatible with earlier versions of Excel.

A couple of commenters expressed concern that the Excel Spreadsheets did not contain all of the information necessary to comply with the analysis required (timing of the event (hour, minute, second). Form 1 contains the time of the event including the hour, minute and second for t(0) and a graph of frequency data for each event in the list. The time for each BA's t(0) may vary from this time due to different sample rates of data and physical proximity to the contingency. Since this standard does not identify an "A Point" or "B Point" but calculates an "A Value" and "B Value", providing an exact time for these provides little value. T(0) is the focus of the measurement process and is the first observed change in frequency of the event. Also added to Form 1, the BA can enter the time zone of its data and the time of t(0) will be converted to the correct time in that zone. We agree that the proper selection of t(0) is important. This can be viewed on the "Graph 20 to 52s" worksheet. When set correctly, the first change in frequency of the event will be exactly in the center of the graph on the vertical grid line.

Some commenters felt that it would be useful if the SDT could develop a completed form as an example to help entities better understand the methodologies used in the form. Form 2 contains actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.

A couple of commenters question the meaning of "master event list" in FRS Form 2. The "Master event list" refers to the event list contained in each Interconnection's Form 1.

Organization	Yes or No	Question 9 Comment
Seattle City Light	Negative	Answer: No Comments: o LADWP and SCL note that Form 2 is not compatible with prior versions of Excel-it won't even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.

Organization	Yes or No	Question 9 Comment
Response: Excel 2003 versions of all forms have been developed.		
Seattle City Light	No	o LADWP and SCL note that Form 2 is not compatible with prior versions of Excel-it won't even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.
Response: Excel 2003 versions of all forms have been developed.		
Associated Electric Cooperative Inc	No	AECI believes the SDT could spare our industry both confusion and inconsistency, by specifying that identified Interconnection Disturbances include both Point A and Point B to the hour, minute, and second. While this introduces some risk of Entities over-automating their data-reports, the benefits for Eastern Interconnection respondents would be tremendous. Cautions and disclaimers should be placed on both Form 1 and Form 2, to assure respondents manually inspect their frequency data and pinpoint the specific inflection-point samples.
Response: Form 1 contains the time of the event including the hour, minute and second for t(0) and a graph of frequency data for each event in the list. The time for each BA's t(0) may vary from this time due to different sample rates of data and physical proximity to the contingency. Since this standard does not identify an "A Point" or "B Point" but calculates an "A Value" and "B Value", providing an exact time for these provides little value. T(0) is the focus of the measurement process and is the first observed change in frequency of the event. Also added to Form 1, the BA can enter the time zone of its data and the time of t(0) will be converted to the correct time in that zone. We agree that the proper selection of t(0) is important. This can be viewed on the "Graph 20 to 52s" worksheet. When set correctly, the first change in frequency of the event will be exactly in the center of the graph on the vertical grid line.		
Bonneville Power Administration	No	BPA believes the form is not easily understood and is overly complicated for what it is trying to accomplish. BPA believes the form might work for an internal evaluation, just not for an external audit. Compliance is based on this form. BPA believes the standard needs to be simplified and possibly returned to a data gathering standard.

Organization	Yes or No	Question 9 Comment
Response: The addition of "Adjustments" to the analysis did add complexity to the Form. These were added based on comments received from the industry on previous postings. Some of these "Adjustments" may be removed as the field trial progresses if they are not utilized. In the latest Form 2, version 6, the multiple time period averages were removed since the final average period was selected based on the results of the first round of the field trial evaluated last fall. However, Form 2 is important to the standard in that it achieves the requirement of measuring frequency response in the same manner for all Interconnections. Returning Form 2 with Form 1 allows validation of the selection of t(0) which is critical for this requirement. **The SDT does not believe that it can revert back to a "data gathering" standard. The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.**		
FPL	No	FRS Form 2 - Two-second Sample DataInstructions tab/worksheet: What is referred to as or meant by the 'master event list'? 4. - Regarding 2 second sample rate for 25 minutes starting 2 minutes before event begins and 15 minutes after it begins, does this add up to 25 minutes or are additional minutes being required for collection? Also, FPL can report frequency at this rate, but can only report load in MW every four seconds. Move to 4 second sample rate.6-8. - Possible to add button to auto-populate cells C8 and C11 in 'Entry Data' tab from the new column C and cell identifying the desired frequency change time and simplify these steps? 10. - Clarify where the "Copy" button is. Is it the one in the 'Data' tab or worksheet? Entry Data tab/worksheet:Step 6 should also be or be moved to the "Instructions" worksheet.Are the values in column C in the "Data" worksheet labeled "Total Lost Generation" the same as those in column AQ in the "Evaluation" worksheet? If so, why are they not both labeled "Net Actual Interchange"? What is the definition of "Non Conforming Load" in column E?
Response: "Master event list" refers to the event list contained in each Interconnection's Form 1.		

Organization	Yes or No	Question 9 Comment
The inconsistency in the data sample totals has been corrected. The absolute minimum amount of data required for the full analysis is two minutes before the beginning of the event to 15 minutes after the beginning of the event. The calculation rate of "Load" can be at a different rate than the AGC scan rate. The Load data is not used in measuring performance. The variability of Load can impact measured performance and can be observed on the "BA Load Dampening" worksheet graph. On some Interconnections, load dampening can be observed in the data. Using the historian "data sample" collection option, it will fill the spreadsheet with the same value of Load, changing at the calculation rate. The "auto populate" of cells C8 and C11 is a good idea. A couple BAs did this during the first phase of the field trail. The problem is that the event time of t(0) in column C was set using 2 second scan data in one part of the Interconnection and the beginning of the event may be shifted one or two scans when frequency is scanned less often. This would make this automation difficult for the value in C8. It is critical for the measure for t(0) be set correctly. The value of C11 is less critical and is not used in the initial primary Frequency Response Measure. It is only used to demonstrate delivery of primary frequency response during the frequency recovery period. The location of the "Copy" button has been clarified. Step 6 on the "Data Entry" worksheet was added to the "Instructions" worksheet. The value in column C in the "Data" worksheet labeled "Total Lost Generation" is for single BA Interconnections only. It takes the place of "Net Actual Interchange" for multiple BA Interconnections. Column "AO" on the "Evaluation" worksheet is not the same as the "Contingent BA Lost Generation" data on the "Evaluation" worksheet. The "Contingent BA Lost Generation" data is only used by multiple BA Interconnection BAs not Single BA Interconnections. The "Data" worksheet for the "Single BA Interconnection" Forms has an n/a in columns G, H and I and should not be used by BAs in these Interconnections. This is noted on their "Instructions" worksheet. This should explain why they are not labeled the same. Non-conforming Load is Load that changes abnormally different than the conventional diurnal load pattern of a Balancing Authority Area. Non-conforming Load becomes significant when the net change within a few minutes is greater than a BA's L_{10} limit. The importance here is that this Load change can be ten times larger than some BAs' FRO and makes measuring the SEFRD inaccurate. An example of non-conforming load would be an arc furnace of a significant size. Thank you for your comments and the effort to find each of these items.		
ISO/RTO Council Standards Review Committee	No	If we are not mistaken, Form 2 is added as the last sheet in the Form 1 spreadsheet file. Apart from that, however, there are other sheets added to the previous Form 1. But this Comment form makes no mention of the changes, nor is there a question in

Organization	Yes or No	Question 9 Comment
		the Comment Form asking whether the additional information should be requested. We believe this is a significant change to the standard and many commenters may have missed the opportunity to comment on it. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided. We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to keep data requirements to only what is minimally needed to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a multiple sheet form for additional data collection. Where the SDT deems the additional data sheet or information not necessary to support FRS reporting, then we suggest the SDT to hide those pages not required for the standard so as to avoid confusion, and/or to remove those analytical pages not directly used in the standard.
Response: The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden. **Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled "BA Form 2 Event Data" that will contain the single event data from each of the BA's Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The "Time Zone Ref" worksheet was added to allow the ability of the BA to enter the time zone of its data and the spreadsheet will calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous**		

Organization	Yes or No	Question 9 Comment
versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the "Data" worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BAs that utilize variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column I of the "Data" worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA's SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your "master" Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.		
Independent Electricity System Operator	No	If we are not mistaken, Form 2 is added as the last sheet in the Form 1 spreadsheet file. Apart from that, however, there are other sheets added to the previous Form 1. But this Comment form makes no mention of the changes, nor is there a question on the additional information requested. We have a concern over this omission of attention or oversight. Compared to the previous version, Form 1 has been significantly expanded to include not only additional sheets but much more comprehensive data requirements even on the Data Entry sheet itself. This makes data submission a very time-consuming task but the justification for requiring detailed data entry has not been provided. We question the need for such expansion on data entry requirements. We have yet to see the reason for expanding Form 1 in assisting a BA to provide the data needed to comply with the standard, hence we do not see how adding a Form 2 can help in that regard. We suggest the SDT to look at the basic need for data submission that would suffice to support the FRS reporting process. Where the SDT deems additional data entry sheets to be necessary, it should provide the rationale for expanding from a 2 sheet form into a multiple sheet form for additional data collection.
Response: The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden.		

Organization	Yes or No	Question 9 Comment
Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled "BA Form 2 Event Data" that will contain the single event data from each of the BA's Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The "Time Zone Ref" worksheet was added to allow the ability of the BA to enter the time zone of its data and the spreadsheet will calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the "Data" worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BA's that utilize variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column I of the "Data" worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA's SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your "master" Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.		
Los Angeles Department of Water and Power	No	LADWP notes that Form 2 is not compatible with prior versions of Excel-it won't even open in Excel 2003 (which is still widely used)-and requests that all spreadsheets and calculation tools developed under 2007-12 be revised to support common software of the past 10 years.
Response: Excel 2003 versions of all forms have been developed.		
Tucson Electric Power	No	TEP feels that Form 2 is a useful tool for internal BA use and should not be used for compliance purposes.
Response: Form 2 is not intended to be used to reflect compliance but rather for consistency in reporting.		

Organization	Yes or No	Question 9 Comment
Form 2 was developed so consistent analysis of each event could be validated. During the first round of the field trial, many BAs selected the incorrect t(0), some provided data that was filtered or utilized data compression techniques that caused the analysis to be incorrect. With Form 2, the selection of t(0) can be quickly evaluated and data quality reviewed. The proper selection of t(0) can be made and Form 1 corrected providing validated consistent results.		
MRO NSRF	Yes	: It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form
Response: All versions of Form 2 contain actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.		
Xcel Energy	Yes	It would be useful if the drafting team could develop a completed form as an example to help entities better understand the methodologies used in the form.
Response: All versions of Form 2 contain actual data for frequency and NAI of an event. Sample data was added for each of the adjustments to demonstrate their use and impact on the analysis.		
Ameren	Yes	We agree that the spreadsheet is meaningful, but still needs to be vetted through the field trial process, with improvements made based on experience in its use.
Response: We completely agree.		
Imperial Irrigation District	Yes	
Northeast Power Coordinating Council	Yes	
SERC OC Standards Review Group	Yes	
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 9 Comment
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Progress Energy	Yes	
Southern Company	Yes	
Energy Mark, Inc.	Yes	
Florida Power & Light Company	Yes	
FMPP	Yes	
ISO New England Inc	Yes	
NV Energy	Yes	
American Electric Power	Yes	
South Carolina Electric and Gas	Yes	
Cleco Corporation	Yes	
Manitoba Hydro	Yes	
Constellation Energy Commodities Group	Yes	

Organization	Yes or No	Question 9 Comment
Great River Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Duke Energy	Yes	
Keen Resources Asia Ltd.	Yes	

10. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1.

Summary Consideration: Many of the commenters referenced other questions in the comments. The SDT asked them to review the response to those earlier questions rather than repeating the responses here.

Several commenters pointed out that there was a discrepancy between the Background Document and Attachment A regarding the calculation of the BA FRO. The SDT has corrected the reference so both documents agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.

Several other commenters indicated that Supplemental Regulation Service was not an appropriate method to provide Frequency Response. The SDT agrees that it is inappropriate to expect supplementary regulation to transfer Frequency Response successfully, however the SDT did not want to prevent any innovative solution that will transfer Frequency Response through the use of a pseudo-tie among Balancing Authorities. Also, the SDT believes that Balancing Authorities exchanging Supplementary Regulation via a pseudo-tie have to be consistent in the removal or inclusion of Supplementary Regulation in their actual net interchange measurement as well as in all events across the measurement period.

Many commenters were concerned that the BA could be responsible for supplying an infinite amount of Frequency Response. They indicated that a BA could not prepare for this in its planning process. The SDT agrees that the proposed standard was not clear on this subject and added language in the “Criteria for Selection of Events” section of the revised Attachment A to limit the amount of Frequency Response a BA would be required to provide in order to be compliant with the standard.

Some commenters were concerned with the wording in Requirement R5. They indicated that the wording needed to say “greater than or” instead of “at least”. The SDT removed the requirement and combined it with the revised Requirement R2 and the new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.

Many commenters did not agree with requiring the BA to provide Frequency Response. The NERC Functional Model and FERC both cited the BA as the responsible entity for providing Frequency Response. T There are several different methods available to the BA to provide Frequency Response and the SDT has included these in the Background Document.

Some commenters were concerned with the threshold that the SDT recommended for the Eastern Interconnection. Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere **in** the East. This is the reason for the higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.

A few commented did not agree with lowering the minimum Frequency Bias Setting. Early research by Nathan Cohn on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased. The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

Some commenters had concerns about the use of the RSG as a means to provide Frequency Response, and the SDT modified the Background Document to further explain how an RSG (now FRSG) could supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."

A couple of commenters indicated that the median was not the proper method to use for the calculation of the FRM. Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response. While the median is not perfect, the median approaches a BA's typical performance after 15-20 observations and more observations give a higher confidence in the estimate of the BA's performance.

Organization	Yes or No	Question 10 Comment
MRO NSRF	Negative	It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they

Organization	Yes or No	Question 10 Comment
		can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of FR that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.0? Is the BA expected to provide a limitless amount of frequency response?). Also, is that event excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, the Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately. In the first paragraph of R5 delete "at least" and replace with "greater than or". This phrase would now read "…absolute value is greater than or equal to one of the following:" "Equal to or greater than" accurately identifies the expectation, the current phrasing will lead to confusion and mis-interpretation. Bullet #1 of R5: The minimum % is based upon the "estimated yearly Peak Demand". During the NERC webinar it was mentioned that this minimum would move to being based on historical reporting of Peak Demand. Where does the SDT stand on this item? Please provide clarification.
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		

Organization	Yes or No	Question 10 Comment
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
JDRJC Associates	Negative	Support Midwest ISO Comments
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Lincoln Electric System	Negative	Please see comments submitted by the MRO NSRF. (See comments for Question 5 submitted by the MRO NSRF.)
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified**		

Organization	Yes or No	Question 10 Comment
the requirement and believes we have implemented the intent of your suggestion. **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Madison Gas and Electric Co.	Negative	Please see the MRO NSRF comments
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Midwest Reliability Organization	Negative	Please see the comments submitted by MRO NSRF. As MRO Sector 10 we agree with MRO NSRF position and recommendation to vote negative for this ballot.
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Muscatine Power & Water	Negative	"MPW agrees with the comments submitted by the MRO-NSRF."

Organization	Yes or No	Question 10 Comment
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Nebraska Public Power District	Negative	NPPD joins it’s comments with comments submitted by the Midwest Reliability Organization - NERC Standards Review Forum (MRO NSRF) submitted on December 8, 2011.
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified the requirement and believes we have implemented the intent of your suggestion.** **The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.**		
Omaha Public Power District	Negative	Please see MRO's comments submitted via Comment Form.
Response: The SDT agrees with you that there was not a clear statement as to the maximum amount of Frequency Response that a BA would have to provide. The SDT has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide. **The SDT has removed Requirement R5 and combined it into Requirement R2 and a new Requirement R3. The SDT has modified**		

Organization	Yes or No	Question 10 Comment
the requirement and believes we have implemented the intent of your suggestion. The SDT has corrected the reference so that both Attachment A and the Background Document agree. The drafting team is proposing to use historical information rather than forecasted information for the allocation of the Frequency Response Obligation.		
FirstEnergy Corp.; FirstEnergy Energy Delivery; FirstEnergy Solutions;Ohio Edison Company	Abstain	FirstEnergy appreciates the hard work of the drafting team but needs more time to review the standard with internal business units and with our RTO. Therefore at this time we must abstain.
Response: The SDT thanks you for your clarifying comment.		
	Abstain	As a qualified professional statistician I abstain from voting "affirmative" or "negative" on this standard because it violates two fundamental statistical best practices. 1. In the Standard, the definition of Frequency Response Measure (FRM) is statistically wrong. The median is an improper statistical measure of Frequency Response because --it truncates large excursions which are the specific subject of Frequency Response control, not normal operating frequency errors which are self-correcting and are the subject of CPM control; --it is non-linear; --it is non-summable over the interconnection; in other words, the individual BA medians don't add up to the interconnection median, in complete incompatibility with CPM control which requires summability of BA performances into the interconnection's performance. Moreover, it is mathematically impossible to sum the medians of the BAs in a Reserve Sharing Group (RSG) into the RSG's median: in other words, the RSG's median cannot represent the sum of the medians of its members. The last paragraph on page 5 of the Background Document is patently wrong, invented, and supported in no probability & statistics literature whatsoever. As a practicing statistician, I hereby give testimony to the utter falsehood of the statement that "In general, statisticisns use the median as the best measure of central tendency when a

Organization	Yes or No	Question 10 Comment
		population has outliers." (See http://www.robertblohm.com/BestStatistic.doc for an explanation of "best statistic" which is a highly technical and central topic in modern probability theory and statistics.) Also, "outliers" are falsely and rhetorically claimed to be "noise" when in fact they are the "events" that are the specific subject of Frequency Response. It is well known that they do not "fit" a normal distribution. They are distinct from the normal operating errors that are the subject of CPM control. The paragraph does correctly conclude that the linear regression more accurately incorporates outliers than the median does, although the paragraph uses rhetoric by calling this improvement "skew" as if it is distortionary when, in fact, the median distorts the reality. 2. The sample pre-selection described in Attachment A, Event Selection, Criteria 2 & 7, violates the fundamental statistical procedure of unbiased sampling. A population is governed by a single "process" which, when stationary, is represented by a fixed probability distribution. In this case the population is several years of events (which are the subject of Frequency Response), not of normal operating control errors which are the subject of CPM control. A sample is governed by a single process that approximates the process governing the population as the sample gets larger, in this case if it includes several years of data. Samples are measured "as they come", no triage/filtering allowed, and they are called "stratified" when their distribution approximates the population distribution. Unlike normal operating errors, samples of events are not evenly distributed over a year. The attempt in criteria 2 & 7 to pre-select only certain events, and not others, in such a way that the selected events occur evenly throughout the year, is papently wrong because it is trying to "fit" events into a process (even distribution over time) that does not govern events, but that instead governs normal operating errors that are the subject of CPM control, not of this Frequency Response standard. In other words, criteria 2 & 7 confuse Frequency Response with CPM, and events with normal operating errors. The result is a false, biased sample which destroys the integrity of this standard. Paragraph 4 on page 5 of the Background Document, on the other hand, provides a statistically correct description of event selection without sample pre-selection and should

Organization	Yes or No	Question 10 Comment
		followed instead of the erroneous criteria 2 & 7 in Attachment A. The reason I do not vote "negative": the risk-based approach to determining FRM, that the Background Document mentions in paragraph 4 of page 4 is being evaluated by the drafting team for application in this standard, should be considered for deployment as soon as possible to replace the administered method currently proposed in this standard, because the administered method lacks any technical justification. No such justification was ever attempted in the development of this standard. The administrative method of determining FRM is therefore but a highly dubious "quick fix" until the risk-based method is evaluated and implemented. The administrative method is in fact perverse because it discourages BAs from reducing their contribution to frequency error by refusing to reduce the BA's FRO accordingly, and because it encourages BAs to contribute to frequency error without increasing their FRO.

Response: The word "average" is a generic term to represent central tendency. The term is often used synonymously with the arithmetic "mean".
The issue with measuring Frequency Response is that a BA's calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.

Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the East typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute Load changes can easily wash this contribution out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.

Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response.

A regression would be appropriate if you were trying to forecast "calculated" frequency response for a BA in a multi-BA Interconnection.

While not perfect, the median approaches a BA's typical performance after 15-20 observations. More observations give a higher

Organization	Yes or No	Question 10 Comment
confidence in the estimate of the BA's performance.		
Associated Electric Cooperative, Inc.	Affirmative	Please see comments submitted by John Bussman of AECI. Thanks, Chris Bolick
Response: Please refer to our earlier question responses to Mr. Bussman's comments.		
Southwest Power Pool, Inc.	Negative	Please refer to the IRC Standards Review Committee comments which SPP is a party to for our concerns and recommendations for this standard.
Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.		
City Utilities of Springfield, Missouri	Affirmative	SPRM supports the comments from SPP.
Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.		
Oklahoma Gas and Electric Co.	Affirmative	See comments submitted by the Southwest Power Pool
Response: The SDT cannot find any comments submitted by the IRC Standards Review Committee.		
Electric Reliability Council of Texas, Inc.	Affirmative	The Applicability of BAL-003-1 should be clarified. Specifically, Section 1.2 should be changed from "Reserve Sharing Groups (where applicable)" to "Reserve Sharing Group whose intent includes meeting Frequency Response Obligations". Regarding Data Retention: 1. As the standard is currently drafted, both the BA and the RSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records. 2. In the first and second paragraph, the reference to 'three calendar years' should be specified to be the 'previous three calendar years'. 3. In the third paragraph, it should be clarified who is required to keep

Organization	Yes or No	Question 10 Comment
		information related to non compliance if the BA belongs to an RSG – the BA or the RSG or both. 4. In the fourth paragraph, it should be clarified for what length of time the last audit records must be retained.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. **1 & 3 - The SDT believes that the reporting entity would be the responsible entity to maintain records. The SDT also believes that once a BA has declared itself as part of an FRSG then the FRSG would be the responsible entity with the obligation to maintain records.** **2 - The SDT agrees with your second comment and has made this modification.** **4 – The last audit record should be kept until the next audit.**		
Midwest ISO, Inc.	Affirmative	We would like to thank the drafting team for developing a standard responsive to the FERC Orders.
Response: The SDT thanks you for your affirmative response and clarifying comment.		
SCE&G	Affirmative	We feel that frequency response is a function of a contingency event and the Purpose Statement should recognize this relationship. We suggest the following insertion in the Purpose Statement. Purpose: To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations (due to a contingency event) and supporting frequency until the frequency is restored. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Organization	Yes or No	Question 10 Comment
Response: The SDT thanks you for your affirmative response and clarifying comment. The SDT believes that the Purpose Statement you are recommending is basically the same as what the SDT is proposing. For this reason the SDT has decided to propose their Purpose Statement for use in the proposed standard.		
SERC Reliability Corporation	Affirmative	Please see comments submitted by the SERC Operating Committee standards subgroup for technical suggestions to improve the standard.
Response: Please refer to the earlier question for the SDTs responses.		
Tennessee Valley Authority	Affirmative	Comments submitted by SERC OC Standards Review Group. TVA votes affirmative with comments previously submitted by SERC.
Response: Please refer to the earlier questions for the SDTs responses.		
Louisville Gas and Electric Co.	Negative	We support the comments in the SERC OC Standards Review Group Comments.
Response: Please refer to the earlier questions for the SDTs responses.		
AEP, AEP Marketing, AEP Service Corp.	Negative	AEP's negative ballot is primarily due to our concerns regarding R1. Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Response: Please refer to our response for Question #1.		
Alberta Electric System Operator	Negative	Besides the standard, the posting has two attachments, supporting material and two forms. It is not clear how enforcement will be applied given the array of explicit and implicit requirements throughout this package, and the use of undefined terminology, which will be subject to interpretations. In the SDT response to our comments to the first draft of this standard it was stated that “The expectation is events will be selected by the Balancing Authorities. The Balancing Authority may exclude events from consideration for specific conditions

Organization	Yes or No	Question 10 Comment
		such as data quality issues. " Based on the SDT's response, it is our understanding that, for the purpose of the FRM calculation, BAs could exclude or include events based on specific conditions consideration, such as data quality or event suitability (e.g. BA separation from the Interconnection). However, the standard as currently drafted, does not have any provisions to this effect. Please include such provisions in the body of the standard.
Response: The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry. **The SDT recognizes that data may not be available for specific events and therefore has provided in FRS Form 1 a means to exclude an event. Additionally if an entity has separated from an Interconnection this could be reason for excluding that event from its FRM calculation since the frequency it would be responding to would not be the Interconnection wide frequency. The risk caused by excluding events is that the measurement process has shown that a limited number of events does not provide suitable calculation.**		
Ameren Energy Marketing Co.; Ameren Services	Negative	We believe that this is good start to a worthwhile standard, but the following issues need to be addressed in this standard: (1) The FRM methodology has not been fully vetted through the field trial process. (2)Adjusting the minimum of the Frequency Bias Setting, while an appropriate adjustment for AGC control in the ACE equation, should not be at the expense of L10 as used in BAL-001, R2. (3) The absence of any resource specific frequency response requirement in NERC standards is an issue that must be address somewhere. As the resource portfolio of our industry changes(expedited by recent EPA rulemaking), the resources used for traditional primary frequency response are becoming a lower percentage of the mix. New resources and existing resources that have not provided primary frequency response need to be incorporated into the available frequency response discussion. (4) BAL-003 is only applicable for an interconnected system, conditions that are

Organization	Yes or No	Question 10 Comment
		created by islanding and other emergences are not address here(nor should they), but need to be address within the EOP family of standards, so that adequate primary frequency response is available during emergency situations.

Response: (1) – The issue with measuring Frequency Response is that a BA's calculated performance (as opposed to actual performance) is highly variable event to event. This is particularly true for a single BA in a multi-BA Interconnection.

Calculated Frequency Response has a very large noise to signal ratio. A 5,000 MW BA in the Eastern Interconnection typically is only called to contribute about 10-15 MW for the loss of a large unit. Its minute to minute Load changes can easily wash this contribution out. An arithmetic mean or regression analysis will be influenced by noise-induced outliers.

Statisticians note that the median is a more accurate measure of central tendency than the mean when analyzing a sample that is small and or where scores vary widely. This is the case when estimating a BA's Frequency Response.

A regression would be appropriate if you were trying to forecast "calculated" frequency response for a BA in a multi-BA Interconnection.

While not perfect, the median approaches a BA's typical performance after 15-20 observations. More observations give a higher confidence in the estimate of the BA's performance.

- The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

(2) - The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

Organization	Yes or No	Question 10 Comment
The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient Frequency Response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost. Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect. (3) – The SDT agrees that the issue you cite should not be covered in this standard. The SDT will forward this comment on to the appropriate entity at NERC.		
PJM Interconnection, L.L.C.	Negative	PJM does not believe that the BA should be the entity responsible for the frequency response obligation, moreover the SDT has not sufficiently vetted the issue of applying the response requirements on an entity that cannot provide that service. PJM is concerned that the proposed draft does not explicitly cover the FERC Order 693 directives in the proposed requirements and rather addresses the directives indirectly in the attachments. This matter of mandatory vs. informational attachments must be formally clarified before approval can be given for this approach. PJM does not agree with the additional clarifying phrases being incorporated into the requirements. Explanatory phases should be included as text boxes as proposed in NERC's Risk Based Methodology.
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.		

Organization	Yes or No	Question 10 Comment

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Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.

Attachments that are referenced within a Requirement are mandatory and enforceable.

The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.

Organization	Yes or No	Question 10 Comment
Potomac Electric Power Co.	Negative	The proposed standard is not reliability centered and will not improve reliability. 5) Potomac Electric Power Company supports the comments provided by PJM.

Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.

There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.

Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a

Organization	Yes or No	Question 10 Comment
need for a generator performance obligation, they are encouraged to submit a SAR to that effect. Attachments that are referenced within a Requirement are mandatory and enforceable. The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.		
Atlantic City Electric Company	Negative	See comments submitted by David Thorne in Segment 1, Potomac Electric Power Company
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost. Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect. Attachments that are referenced within a Requirement are mandatory and enforceable. The SDT has been instructed to include a "reliability outcome" within the requirements. The SDT will forward your concerns about the wording to the Standards Committee Quality Review group for consideration.		
Avista Corp.	Negative	This standard should be designed for each interconnection explicitly rather than one size fits all. Frequency is an interconnection issue and response is driven by the interconnection's topology. One size does not fit all for interconnections. This

Organization	Yes or No	Question 10 Comment
		standard should be designed around the explicit needs of each interconnection. Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response.
Response: The SDT believes that an Interconnection has the capability to request a variance (especially one that is more restrictive), however the SDT has tried to prevent the need for variances by respecting the individuality of each of the Interconnections in setting Interconnection Frequency Excursion Threshold Values, Interconnection Frequency Response Obligations and the Frequency Bias Setting Minimums as noted in Attachment A. **Early research by Nathan Cohn[5] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.** **The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.**		
Beaches Energy Services; City of Bartow, Florida; Tampa Electric Co.	Negative	We thank the SDT for their hard work and diligence in moving this Project forward. However, I have some concerns that cause me to not support the standard in its current form. In general, I believe that there has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. I also believe that the proposed standard does not meet the intent of the Final SAR

[5] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 10 Comment
		or Supplemental SAR. The “Final SAR” was to develop methods by which a performance based standard would eventually be developed. The Final SAR states: “The proposed standard’s intent is to collect data needed to accurately model existing Frequency Response. There is evidence of continuing decline in Frequency Response in the three Interconnections over the past 10 years, but no confirmed reason for the apparent decline. The proposed standard requires entities to provide data so that Frequency Response in each of the Interconnections can be modeled, and the reasons for the decline in Frequency Response can be identified. Once the reasons for the decline in Frequency Response are confirmed, requirements can be written to control Frequency Response to within defined reliability parameters.” BAL-003-1 is beyond the scope of this “Final SAR”. For instance, “the reasons for the decline in Frequency Response” were not confirmed to our knowledge; and the field trial is not completed to our knowledge. The Supplemental SAR adds to the scope of the Final SAR: “To provide a minimum Frequency Response Obligation for the Balancing Authority to achieve, methods to obtain Frequency Response and provide a consistent method for calculating the Frequency Bias Setting for a Balancing Authority. In addition, the standard will specify the optimal periodicity of Frequency Response surveys.” Please note that the Standards Development Roadmap does not confirm whether this Supplemental SAR was ever approved; hence, I question whether this is actually part of the scope of the SDT. Be that as it may, the Supplemental SAR does not eliminate the pre-requisite contained in the Final SAR to determine the reasons for the decline in frequency response and confirm them before establishing “defined reliability parameters”. In addition, the standard does not meet the scope requirements of the Supplemental SAR.
Response: The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012. **The SDT agrees that the original SAR was strictly for data collection. However, a supplemental SAR was developed to address the FERC March 18, 2010 Order and was subsequently approved by the industry.**		

Organization	Yes or No	Question 10 Comment
Constellation Energy Commodities Group	Negative	Please see submitted comments for additional detail behind the negative vote.
Response: Please see the SDT responses to your comments to the earlier questions.		
Energy Mark, Inc.	Negative	The issue of Median, Mean, Regression needs to be resolved using Field Trial data. This should be able to be completed before the end of January 2012. The FRO and Minimum Bias Setting allocations should be determined using a single allocation method and a single data set. Wording changes are needed in the Requirements to indicate compliance in all cases for all BAs. In general, although this standard has many weaknesses, its implementation with small modifications will be better than failure to implement it.
Response: The drafting team is recommending use of the median for the purposes of determining a BA FRM over multiple events. This decision is based on the determination that, while it may not be perfect, it is better than the other alternatives available at this time. The drafting team recognizes that in the future a better methodology might be found; based on the data available at this time the median allows us to move forward to implement a response requirement. **The drafting team understands your concern of using the historical numbers for the FRO allocation and the projected number as the basis for the minimum Frequency Bias Setting. However, after discussions, the drafting team believes that at this time, minimizing the changes to the current Frequency Bias Setting process provides better comparability for the purpose of evaluating the impacts of reducing the minimum setting requirement. In the alternative, the drafting team feels that allocating the FRM based on historical data provides less room to game the process since the numbers used for allocation can be verified independently.** **The SDT has modified the requirements and believes that your concern has now been addressed.** **The SDT thanks you for your comment.**		
Energy Mark, Inc.	Negative	The Time Horizon for R1 is Operations Assesment. It should be Real Time. Frequency

Organization	Yes or No	Question 10 Comment
		Response is a service that is automatic. It does not require operator action to activate the service. It requires that the operator set-up the system to provide the automatic response before an event requiring Frequency Response occurs. Unlike other Real Time services, if the operator fails to set-up the system to provide this service before Real Time, there is no action that the operator can take to provide the service in response to an event. Many other actions in the standards required by the system operator are considered to be Real Time because the operator can take action after an event occurs. It does not make sense to consider an action that must be taken before Real Time as Operations Assessment.
Response: The requirement does not fall into a single category. The operator is constantly taking actions some of which were set in a "longer term" horizon, some in a "real-time" horizon and this is an after-the-fact measure.		
Fort Pierce Utilities Authority	Negative	FPUA supports the comments submitted by Florida Municpal Power Agency (FMPA) through the formal comment process.
Response: Please refer to the SDT response to the comments received from FMPA in the earlier questions.		
Hydro One Networks, Inc.	Negative	Hydro One is casting a negative vote for this project. We support and subscribe to the comments submitted by NPCC on behalf of its members. In summary, the comments are: 1 o Use of 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz. 2 o Use of installed capacity in determining the Frequency Response Obligation. 3 o The sampling interval should be tuned on a per Interconnection basis to support HQTE's characteristics. 4 o NPCC does not advocate the use of supplemental regulation as a method of procuring frequency response. 5 o BAL-003-1 is applicable only to Balancing Authorities and Reserve Sharing

Organization	Yes or No	Question 10 Comment
		Groups. A common concern that has been expressed in the industry is that the burden of compliance is being placed solely on Balancing Authorities while the main sources of discretional frequency response are generators. 6 o Balancing Authorities must be able to provide sufficient frequency response and be able to and the proper frequency bias settings applied in their AGC systems are necessary. 7 o In the formula for determining the Balancing Authority's FRO allocation, installed capacity is used. Is there a clear and consistent definition for installed capacity? Considering the growth of wind energy development, the delivered energy from wind generation over longer time horizons will be substantially less than the machine nameplate ratings. 8 o The background document refers to the use of peak generation instead of installed capacity. Which shall be used? o Additional minor issues for the SDT consideration that should be addressed: ? A link should be provided in the standard to FRS Form 1, or instructions provided for how entities may find the form. ? In the definitions, FRS should be spelled out before using the acronym.

Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for its higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.

2, 7 & 8 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses "historical data" to circumvent the problem you have described.

Organization	Yes or No	Question 10 Comment

3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.

4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.

The drafting team believes the following are valid methods of obtaining Frequency Response:

- **Regulation services.**
- **Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.**
- **Through a tariff (e.g. Frequency Response and regulation service).**
- **From generators through an interconnection agreement.**
- **Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).**

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

5 – The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.

There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not

Organization	Yes or No	Question 10 Comment
outweigh the effort and cost. **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **6 – The SDT agrees with you comment.** **Additional minor issues** **The Forms will be put on a NERC website and announced once the standard is approved.** **The definition no longer reference FRS Form 1.**		
Independent Electricity System Operator	Negative	The complete IESO's comments on the revised standard are provided through the electronic comment form. The summary below highlights IESO's major concerns with the revised standard: 1)The definition for Frequency Response Measure (FRM): The proposed FRM definition: "The median of all the Frequency Response observations reported annually on FRS Form 1" is problematic. It references an FRS Form 1 which is not included in the definition itself but is in fact an attachment to the standard. In the current NERC Glossary of Terms, there is no such precedence that a definition must rely on the requirements or details in a standard for completeness. Also, it is very cumbersome that when changes are made to FRS Form 1, the definition must be posted for industry comment and balloting, and vice versa. When other standards begin using the term, there will be cross references between standards. This further complicates the update/maintenance problem without any appreciable value. (See complete comment in Section Q1 in the electronic comment form) 2)Attachment A: Attachment A should include only the event selection process and calculations associated with the requirements, including an explanation of what is necessary if variable Frequency Bias Settings are implemented. If other "requirements" need to be specified, such as the reporting time frame stipulated on page 3 of Attachment A, they should be moved to the standard itself but not imbedded in an attachment. (See complete comment in Section Q6 in the electronic

Organization	Yes or No	Question 10 Comment
		comment form) 3)The expanded FRS Form 1 and the addition of a Form 2 ask for data entry that is excessive and whose value has not been demonstrated. (See complete comment in Section Q9 in the electronic comment form)

Response: 1) The SDT has modified the definition to no longer reference FRS Form 1. The definition now reads "The median of all the Frequency Response observations reported annually by Balancing Authorities for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

2) The intent of Attachment A is to describe the process that will be used. There is no intent to require a filing on a certain date and to have the BA prove to the auditor that a filing was made on that date. Rather the requirement is to have an FRM that provides at least the response required of a BA based on it's FRO and provide a high-level overview of the mechanical parts of the process. The drafting team has modified the Requirements and Attachments to address the concerns raised by the comments that indicated requirements were in the Attachments. In order to explain the process, the drafting team believes the information needs to be attached to the standard such that it cannot be changed without input from the industry.

3) The SDT points out that there are no additional data requirements. It is possible that you are seeing more spreadsheets due to them being unhidden.

Form 2 is a separate stand-alone workbook. Form 1 does have a worksheet labeled "BA Form 2 Event Data" that will contain the single event data from each of the BA's Form 2s. Two additional worksheets were added to Form 1 and several worksheets were deleted. The "Time Zone Ref" worksheet was added to allow the BA to enter the time zone of its data and have the spreadsheet calculate the local time of the event from the UTC time. This was added for the convenience of the BA in collecting the correct data for each event and does not require additional data from the BA. The second worksheet added was a worksheet that displays graphs of frequency for each event and the t(0) selected correctly. This was added to aid the BA with data collection and the selection of t(0) since this seemed to be one of the biggest problems during the first phase of the field trial. This graph worksheet does not require the BA to do anything. It is not used in the analysis and can be deleted. Deleting this worksheet will greatly reduce the size of Form 1. None of the data requirements on Form 1 or Form 2 have changed from previous versions. The absolute minimum data needed for this standard is the date/time, frequency and NAI in columns A, B and C of the "Data" worksheet in Form 2. Columns D through I have been totally optional and can be left blank. Column J is the Bias setting in the ACE equation and is important to BA's that utilize Variable Bias. Column K, BA Load, was added by the drafting team in the beginning to see if Load Dampening could be measured as this has been done for several years on one Interconnection. Column I of the

Organization	Yes or No	Question 10 Comment
“Data” worksheet is the only optional data that the BA should use when it is the contingent BA during any of the events evaluated. Utilizing this data will allow the BA’s SEFRD to be calculated correctly and give the BA a full sample set for the annual median calculation. Form 2 is necessary to standardize the measurement process on all Interconnections. You are free to hide any analytical worksheets on Form 1 and Form 2. You can do this on your “master” Form 2 and then build each Form 2 for each event using this master. These additional worksheets are available for BAs to utilize if they find that their performance is below the FRO and will aid the analysis of the contributing causes.		
ISO New England, Inc.	Negative	ISO New England will not vote to approve the standard because it fails to place requirements on generators to provide frequency response. There are four substantive problems: 1 • Using 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz 2 • Using installed capacity in determining the Frequency Response Obligation 3 • The sampling interval needs to be tuned on a per Interconnection basis to support HQTE’s characteristics 4 • Do not advocate the use of supplemental regulation as a method of procuring frequency response Additionally, the SDT must decide on what the purpose of this standard is. If it is to respond to Order 693 then the standard misses the point of defining how often to run Frequency Response Surveys; it does not crisply define the “Interconnection” obligations. If the SDT does want to focus on performance then the issue of who is the default provider must be addressed. As the IRC has noted previously, all BAs do not own the service providers. To create standards that apply to entities that are dependent on other function entities to comply with a standard requirement is of great concern.
Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a		

Organization	Yes or No	Question 10 Comment

contingency inside Florida, but would require the other BAs in the East to continuously carry about 4000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.

2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses "historical data" to circumvent the problem you have described.

3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern.

4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.

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The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR. **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.** **6 – The SDT agrees with you comment.** **Additional minor issues** **The Forms will be put on a NERC website and announced once the standard is approved.** **The definition no longer reference FRS Form 1.**		
JEA	Negative	JEA is not comfortable with a performance based standard as written without more field testing to ensure that net interchange is not skewed by load and generation changes that are not a function of frequency. Since frequency response has components from load and generation resources, and load is not controllable for the most part, seems this standard should be directed at specific generator response methods from the GO/GOP's. This is a wide reaching standard. And, this is a performance standard (if it doesn't perform as designed, it is a violation). Because of this, more testing needs to be completed so we know the model is correct. We are not sure we know how to ensure compliance. Don't agree the standard needs to be performance based.
Response: Based on the studies performed by the SDT, the drafting team believes that a calculation of the median of multiple		

Organization	Yes or No	Question 10 Comment
events addresses the concerns raised by the noise being inside a single event. The studies from the field trial show a convergence of the measurement after approximately 20 to 25 events. **The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012.**		
Kansas City Power & Light Co.	Negative	The proposed Standard BAL-003-1 does not consider the real time operating conditions under which this standard should apply. There are no considerations for the complexities introduced by capacity energy agreements between BA's nor consideration of the differing level of Interconnection Frequency Response needed at times of minimum interconnection load conditions and interconnection peak load conditions.
Response: The method for determining the FRO is based upon the determination of the largest contingency that could occur at any time and does not vary based upon time of day or system conditions. Since the largest contingency could occur at any time, the minimum Frequency Response Obligation necessary to manage the contingency will not be dependent upon the differing conditions that can occur during different times of the day like those referred to in the question.		
Lakeland Electric	Negative	In general; here has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure. Refer to comments submitted by FMPA on LAK behalf.
Response: The SDT is responding to FERC Directives from Order 693 as well as the FERC Order dated March 18, 2010 which mandated development of a standard addressing the Order 693 directives within six months. FERC later granted an extension to provide a standard addressing these issues by the end of May 2012. **Please refer to the SDT response to the comments received from FMPA in the earlier questions.**		
Liberty Electric Power LLC	Negative	Voting no due to SDT addressing FERC directives with attachments instead of in the standard requirements.
Response: The SDT disagrees with your concern about addressing FERC directives within an attachment. If a requirement		

Organization	Yes or No	Question 10 Comment
references specific performance in an Attachment, then the performance described in the Attachment is mandatory and enforceable.		
Manitoba Hydro	Negative	The Applicability of BAL-003-1 should be clarified. Specifically, Section 1.2 should be changed from "Reserve Sharing Groups (where applicable)" to "Reserve Sharing Group whose intent includes meeting Frequency Response Obligations". Regarding Data Retention: 1. As the standard is currently drafted, both the BA and the RSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records. 2. In the first and second paragraph, the reference to 'three calendar years' should be specified to be the 'previous three calendar years'. 3. In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an RSG – the BA or the RSG or both. 4. In the fourth paragraph, it should be clarified for what length of time the last audit records must be retained.
Response: The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members." The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. **1 & 3 - The SDT believes that the reporting entity would be the responsible entity to maintain records. The SDT also believes that once a BA has declared themselves as part of a FRSG then the FRSG would be the responsible entity to maintain records.** **2 - The SDT agrees with your second comment and has made this modification.** **4 – The last audit record should be kept until the next audit.**		

Organization	Yes or No	Question 10 Comment
New Brunswick Power Transmission Corporation	Negative	The compliance burden should not fall on the BA as the provider of Frequency Response (i.e. Primary Control response). In this case the BA per se has no assets, moreover the primary response service providers have no obligations to provide the service, thus the BA potentially could face a situation where there is no physical service to be purchased but there is a mandated standard to comply with. The idea of creating a Primary Response Market as some have proposed does not work without an obligation on some entity to physically provide that service.
Response: The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits. **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.**		
New York State Department of Public Service, National Association of Regulatory Utility Commissioners	Negative	After review of the standard and draft comments to be submitted by industry participants, it appears that there are many areas of the proposed standard that require clarification.
Response: The SDT thanks you for your participation. Please be more specific about what needs clarification so the SDT can address your specific concerns.		

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council	Negative	This standard as written does not place requirements on generators to provide frequency response. There are four substantive problems: 1 • Using 59.6 Hz as an Eastern Interconnection UFLS instead of an actual value of either 59.5 Hz or 59.7 Hz. 2 • Using installed capacity in determining the Frequency Response Obligation. 3 • The sampling interval needs to be tuned on a per Interconnection basis to support HQTE's characteristics. 4 • Do not advocate the use of supplemental regulation as a method of procuring frequency response. It must be decided as to what the purpose of this standard is. If it is to respond to Order 693 then the standard misses the target of defining how often to run Frequency Response Surveys; it does not crisply define the "Interconnection" obligations. If performance is the focus, then the issue of who is the default provider must be addressed. All BAs do not own the service providers. To create standards that apply to entities that are dependent on other functional entities to comply with a standard requirement is of great concern. FRS Form 1 is listed as being an Associated Document. Will it be attached to the standard? The acronym FRS is used in the standard. FRS should be spelled out before its acronym is used. If FRS Form 1 will not be an appendix or an attachment to the document, then a link should be provided to it, or instructions given on how to find it.

Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4000 MW

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New Brunswick System Operator	Negative	Please see comments submitted by the NPCC Reliability Standards Committee and the IRC Standards Review Committee
Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz. 2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described. 3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern. 4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.		

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Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.

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approved. The definition no longer reference FRS Form 1.		
New York Independent System Operator	Negative	The NYISO's comments are included with both the Joint IRC/SRC and Joint NPCC RSC comments.
Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the Eastern Interconnection to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz. 2 – The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses “historical data” to circumvent the problem you have described. 3 – The SDT adjusted the event selection Criteria to address concerns related to response driving frequency back to the pre-event level during the B value measurement period. We believe that this adjustment addresses your concern. 4 – The SDT has a section in the Background Document addressing methods of obtaining Frequency Response. The drafting team believes the following are valid methods of obtaining Frequency Response: • Regulation services. • Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration. • Through a tariff (e.g. Frequency Response and regulation service). • From generators through an interconnection agreement. • Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for		

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Rochester Gas and Electric Corp.	Negative	RG&E supports comments to be submitted to NPCC.
Response: 1 - Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency		

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Orlando Utilities Commission	Negative	Per LPPC comments
Response: The SDT is not sure of the entity you are referencing (LPPC). Therefore, the SDT cannot respond to your comment without further clarification.		
Portland General Electric Co.	Negative	PGE agrees with the WECC whitepaper including the comments and concerns.
Response: see WECC comments.		
PPL Electric Utilities Corp.; PPL Generation LLC	Negative	The PPL Companies do not support proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) primarily because PPL believes it inappropriately subjects Reserve Sharing Groups (RSGs) to the proposed requirements. The proposed Applicability provision states that the mandatory reliability requirements would be applicable to (1) Balancing Authorities and (2) Reserve Sharing Groups (where applicable). However, it is unclear how the proposed requirements would be applicable to an RSG. RSGs typically do not provide a mechanism for sharing automatic Frequency Response. The BA Frequency Response

Organization	Yes or No	Question 10 Comment
		Obligation (FRO) is a formula based on BAs and the Interconnection and has nothing to do with RSGs. Rather, RSGs collectively respond to requests for activation of contingency reserves generally after the request is made by a member Balancing Authority. The Standard Drafting Team should therefore remove RSGs from the Applicability section and should remove all other references to RSGs in the proposed standard.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."		
PPL EnergyPlus LLC	Negative	Please refer to PPL's corporate comments.
Response: The SDT has modified the Background Document to further explain how an RSG (now FRSG) can be used to supply Frequency Response. The SDT has defined a new term "Frequency Response Sharing Group (FRSG)" because it believes that using the presently defined term "Reserve Sharing Group" could cause confusion. The new definition reads "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members."		
Seattle City Light	Negative	LADWP and SCL support project 2007-12's general approach to frequency response, and is prepared to support the ballot once several problematic details are corrected. o LADWP and SCL note that the time allowed to analyze the final "official" set of 25 events for each year, from Dec 15 to Jan 10, is relatively short and coincides with the holiday vacation season
Response: The ERO will be posting preliminary events throughout the year. The criteria contained in Attachment A should allow an entity to evaluate events as they occur. This coupled with the Forms 1 & 2 should allow an entity to be looking forward throughout the year. In addition the standard allows 30-days for providing information.		

Organization	Yes or No	Question 10 Comment
Seattle City Light	Negative	SCL would like to see addressed in the Standard how the case is to be addressed where a BA simply has no frequency response information to provide, as could happen for a small 1-2 generator BA which has its generators out of service for an extended period for maintenance or upgrades. Assuming the BA purchases frequency response services from another entity during this period, is the BA out of compliance with the proposed Standard simply because it has no data report? And how is its next-year obligation to be computed? These issues should be addressed in the Measures or Additional Compliance information. If these are issues for "lawyers" as the Standards Drafting Team indicated during the November 14, 2011, webinar then the team should engage a NERC lawyer to resolve them prior to releasing the Standard for ballot. o Finally, SCL points out that the proposed Standard introduces a new obligation on applicable entities to maintain frequency responsive reserves. Although this obligation does not appear to be unreasonable or problematic in general, compliance may prove difficult for some entities and in some localized areas.

Response: The SDT has a section in the Background Document addressing methods of obtaining Frequency Response.

The drafting team believes the following are valid methods of obtaining Frequency Response:

- **Regulation services.**
- **Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.**
- **Through a tariff (e.g. Frequency Response and regulation service).**
- **From generators through an interconnection agreement.**
- **Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).**

Organization	Yes or No	Question 10 Comment
Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.		
Public Utility District No. 1 of Snohomish County/Snohomish County PUD No. 1	Negative	Public Utility District No. 1 of Snohomish County supports the comments filed by Seattle City Light.
Response: The ERO will be posting preliminary events throughout the year. The criteria contained in attachment A should allow an entity to evaluate events as they occur. This coupled with the Forms 1 & 2 should allow an entity to be looking forward throughout the year. In addition the standard allows 30-days for providing information. The SDT has a section in the Background Document addressing methods of obtaining Frequency Response. The drafting team believes the following are valid methods of obtaining Frequency Response: • Regulation services. • Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration. • Through a tariff (e.g. Frequency Response and regulation service). • From generators through an interconnection agreement. • Contract with an internal resource or Loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response). Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.		
South California Edison	Negative	SCE's "No" vote, like the WECC position, regarding Project 2007-12 is based on the

Organization	Yes or No	Question 10 Comment
Company		following five points: 1) Clarification is needed whether there will/ will not be conflicts between proposed Requirement R3 and the requirements of FERC-approved regional reliability standard BAL-004-WECC-1 - Automatic Time Error Correction 2) Confusion exists between Attachment A and the Background Document: 2a) Attachment A states peak load allocation is based on "Projected" Peak Loads and Generation, versus 2b) The Background Document which states it will use "historical" Peak Load and Generation. 3) Reducing frequency bias obligation is detrimental to reliability. It seems that Lowering the Minimum Frequency Bias Setting from 1% to .8% will result in a lower response, which in turn will lower the natural frequency response. Over time it seems this pattern would lead to poorer response. 4) There is no clear statement of what is expected from the Balancing Authorities and whether or not there is a limit on that expectation. 5) Why are there no requirements on governor installation, settings, and operation for a frequency response standard?

Response: 1) The SDT has removed Requirement R3. The SDT believes that this requirement is duplicative of BAL-005-0.1b Requirements R6 & R7.

2) The SDT has modified both the Background Document and Attachment A to be consistent. The calculation uses "historical data" to circumvent the problem you have described.

3) Early research by Nathan Cohn[6] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.

[6] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 10 Comment
The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations. **4) The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide** **5) The NERC *Functional Model Technical Document* identifies the BA as the entity that manages and deploys Frequency Response. This is because a BA controls the amount and distribution of spinning reserves and also has some control over interruptible resources. This is similar to the relationship between the TOP and voltage control. Even though the TOP may not own generators or capacitor banks, the TOP is still responsible for controlling voltage within limits.** **The industry-approved Standards Authorization Request (SAR) for BAL-003 did not include a performance obligation for generators. The drafting team is obliged to stay within the bounds of its SAR.** **There are two primary reasons the SAR did not apply a performance obligation on generators. First, there are thousands of generators in North America. It would be many times more costly and difficult to implement a standard that measures all generators and verifies performance is properly calculated. Secondly, given the fact that there presently is sufficient frequency response in all Interconnections, the value of implementing a performance obligation on generators at this time would not outweigh the effort and cost.** **Again, the drafting team cannot include requirements beyond the bounds of its SAR. If the commenter(s) believes there is a need for a generator performance obligation, they are encouraged to submit a SAR to that effect.**		
Western Area Power Administration	Negative	1. Reducing frequency bias obligation is a detriment to reliability of interconnection and the proposed standard aims to reduce the bias obligation from the current minimum level of 1% load to 0.8% and subsequently to a lower percentage. 2. The proposed standard is very confusing and complex in regard to data collection

Organization	Yes or No	Question 10 Comment
		and compliance. 3. The proposed standard is encompassing reserve sharing group (where applicable), why? What reserve sharing group operates AGC? It is not clear whether the compliance period is monthly or yearly for R1 & R5. The issue of non-binding standard and whether it serves a purpose to go through complicated data submission and found in compliance or out of compliance without any consequences.

Response: 1. Early research by Nathan Cohn[7] on interconnected power system operations found that control is optimum if a BA's Bias Setting is equal to its natural Frequency Response. If there were to be a difference between the two values, it is preferable to be slightly over-biased.

The drafting team has proposed to bring Bias Setting and natural Frequency Response more in line. The process to do this is outlined in a Procedure developed by the SDT which replaces Attachment B. The Procedure manages a "go slow" approach to making this happen and includes checks to confirm there are not unexpected influences injected into the CPS-related calculations. Based on concerns raised by the industry, the drafting team has modified the Procedure to make the initial minimum Bias Setting 0.9% of peak and has included a provision that the ERO will evaluate the impact caused by a change in minimum Bias Setting. The evaluation will look at both frequency performance and impact on CPS-related compliance calculations.

3. The SDT has modified the Background Document to provide additional information and clarity.

4. The SDT modified R1 so that it no longer applies to an RSG _ the SDT defined new term, "Frequency Response Sharing Group" to address stakeholder concerns that the RSG is not the correct entity. The definition of Frequency Response Sharing Group is:

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members.

3. Requirement R1 is calculated on an annual basis. The SDT has removed Requirement R5 and combined it into Requirement R2

[7] *Control of Generation and Power Flow on Interconnected Systems*, John Wiley & Sons, 1967

Organization	Yes or No	Question 10 Comment
and new Requirement R3. **The SDT made modifications to Attachment A to try to distinguish mandatory performance assigned to the BA from process steps performed by the ERO.**		
Xcel Energy, Inc.	Negative	It is not clear if there is an upper limit to the amount of frequency response expected of the Balancing Authorities under this standard. Except for Table 2 in Attachment A, there is no discussion of an amount of FR expected on a total basis. Balancing Authorities need to know for how many tenths of a hertz they are to respond so they can determine how to plan to meet this requirement. The documents do not appear to provide any boundary on the maximum amount of FR that a BA will provide, i.e. it is not clear what will happen if an event occurs in the Eastern Interconnection that causes the frequency to drop to less than 59.6 Hz (e.g. what if freq dips to 59.0? Is the BA expected to provide a limitless amount of frequency response?). Also, is that event excluded from the list used to calculate the Balancing Authorities' response or is it included with an expectation that it counts the same as any other event. Without a clear statement of what is expected, including whether there is a limit on that expectation or not, the Balancing Authorities cannot know what is expected of them and therefore cannot plan appropriately.
Response: The SDT understands your concern and has added language in Attachment A that caps the amount of Frequency Response that a BA will be required to provide.		
	Negative	59.6 Hz should be used as the Eastern Interconnection URLS. Installed capacity should always be used determining an area's frequency response obligation. I question the use of supplemnetal regulation as a method of procuring frequency response. Is this an acceptable practice throughout all NERC Regions? Each Balancing Authority must be able to provide the required or calculated frequency response and be able to incorporate the proper frequency bias settings in

Organization	Yes or No	Question 10 Comment
		the Balancing Authority's AGC system. A link should be provided in the proposed standard to FRS Form 1.

Response: Florida sees a greater change in frequency for a given contingency than for a comparable event elsewhere in the East. This is the reason for their higher first step of UFLS in Florida. Having all Eastern Interconnection Balancing Authorities carry extra frequency responsive reserves to protect against a target minimum frequency of 59.7 Hz would not protect Florida against a contingency inside Florida, but would require the other BAs in the East to continuously carry about 4,000 MW of frequency responsive reserves to protect against a false trip in Florida if frequency fell below 59.7 Hz but over 59.5 Hz. This is a contingency on the order of 7,000 MW or more. The drafting team compromised and gave the entire Interconnection an obligation based on 59.96Hz.

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Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Organization	Yes or No	Question 10 Comment
The SDT agrees with you comment. The Forms will be put on a NERC website and announced once the standard is approved.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2007-12 Frequency Response (BAL-003-1)

The Project 2007-12 Drafting Team thanks all commenters who submitted comments on the proposed standard, BAL-003-1 which was posted for a 30-day formal comment period from October 5, 2012 through November 6, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 50 sets of comments, including comments from approximately 144 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

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

- Made clarifying changes to the proposed standard including replacing the term "…subject to…: with "…in accordance with…" in Requirement R2.
- Clarified the description of the calculation for the Interconnection IFRO in Attachment A.
- Modified Attachment A and the Procedure to provide consistency with the use of the term "resource contingency criteria".
- Corrected typographical errors in all documents.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy Macdonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowcz	Northeast Power Coordinating Council	NPCC	10
16.	Wayne Sipperly	New York Power Authority	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Group	Erik Ela	NREL Transmission and Grid Integration Group										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vahan Gevorgian	NREL	NA - Not Applicable	NA
2.	Brendan Kirby	Consultant	NA - Not Applicable	NA
3.	Yingchen Zhang	NREL	NA - Not Applicable	
4.	Mohit Singh	NREL	NA - Not Applicable	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6

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

8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC		1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bart McManus	Technical Operations	WECC	1
2.	Kristy Humphrey	Technical Operations	WECC	1
3.	Ayodele Idowu	Technical Operations	WECC	1
4.	Rebecca Berdahl	Policy Development & Analysis	WECC	3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Danny Dees	MEAG Power	SERC	1
3.	Steve Grego	MEAG Power	SERC	5

				1	2	3	4	5	6	7	8	9	10
6.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation`	RFC	1
2.	Annette M. Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

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

5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6
10.	Brent Ingebrigtson	LG&E and KU Services	SERC	3

				1	2	3	4	5	6	7	8	9	10
7.	Group	Greg Rowland	Duke Energy	X		X		X	X				

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

				1	2	3	4	5	6	7	8	9	10
8.	Group	Jason Marshall	ACES Power Marketing 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
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Gerry Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Harrison	AECI	SERC	1, 3, 5, 6
2.	Robert Thomasson	Big Rivers Electric Corp.	SERC	1
3.	Dan Roethemeyer	Dynegy	SERC	5
4.	Adam Guinn	Duke Energy	SERC	1, 3, 5, 6
5.	Brad Young	LGE-KU	SERC	1, 3, 5, 6
6.	Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
7.	Marie Knox	MISO	SERC	2
8.	Terry Bilke	MISO	SERC	2

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

9.	Troy Blalock	SCE&G	SERC	1, 3, 5, 6
10.	Cindy Martin	Southern Co. Services	SERC	1, 5
11.	Todd Lucas	Southern Co. Services	SERC	1, 5
12.	Kelly Casteel	TVA	SERC	6, 1, 3, 5
13.	Joel Wise	TVA	SERC	1, 3, 5, 6
14.	Stuart Goza	TVA	SERC	1, 3, 5, 6
15.	Steve Corbin	SERC Reliability Corp	SERC	10

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	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
11.	Group	Scott Kinney	Avista	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott	Kinney	WECC	1
2.	Bob	Lafferty	WECC	3
3.	Ed	Groce	WECC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utililties of Springfield	SPP	1, 4
2.	Lisa Duffey	Cleco Power	SPP	1, 3, 5
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Stephen McGie	City of Coffeyville	SPP	NA

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
6.	Terry Petzoldt	Kansas City Board of Public Utilities	SPP	3
7.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
8.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
9.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
10.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	Mark Gray	Edison Electric Institute	X		X		X	X				
15.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
16.	Individual	ryan millard	pacificorp	X		X		X	X				
17.	Individual	Stephanie Monzon	PJM Interconnection, LLC		X								
18.	Individual	Richard Vine	California Independent System Operator		X								
19.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
22.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
23.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
24.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
25.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
26.	Individual	Greg Travis	Idaho Power Company	X		X							
27.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
28.	Individual	Michael Falvo	Independent Electricity System Operator		X								
29.	Individual	Brian J Murphy	NextEra Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	Don Jones	Texas Reliability Entity										X
31.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
32.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
33.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
34.	Individual	Kathleen Goodman	ISO New England Inc.		X								
35.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
36.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
37.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
38.	Individual	David Jendras	Ameren	X		X		X	X				
39.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
40.	Individual	Janelle Marriott Gill	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
41.	Individual	Denise M Lietz	Puget Sound Energy	X		X		X					
42.	Individual	Rich Salgo	NV Energy	X		X		X					
43.	Individual	John Tolo	Tucson Electric Power	X									
44.	Individual	Ken Gardner	AESO		X								
45.	Individual	Patricia Robertson	BC Hydro	X	X	X		X					
46.	Individual	Grergory Campoli	New York Independent System Operator		X								
47.	Individual	Robert Blohm	Keen Resources Asia Ltd.								X		
48.	Individual	Marie Knox	MISO		X								
49.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
50.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
MEAG Power	Southern Company Services, Inc - Gen
Associated Electric Cooperative, Inc. - JRO00088	SERC OC Standards Review Group
Avista	Bonneville Power Administration
Nebraska Public Power District	MRO NSRF [Midwest Reliability Organization - NERC Standards Review Forum]
ISO New England Inc.	Last submitted comments of ISO-NE which have not been addressed and, for efficiency sake, do not believe we should be requested to re-submit.
South Carolina Electric and Gas	SERC OC Standards Review Group
Entergy Services, Inc. (Transmission)	Entergy is in agreement with comments submitted by SERC on 11/5/0212.
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing

1. The SDT has made minor modifications to the proposed definition for Frequency Response Measure based on industry comments. Do you agree that these modifications provide sufficient clarity? If not, please explain in the comment area.

Summary Consideration: A few of the commenters felt that the definition applied to all of the observations for both the BA and the FRSG. The drafting team stated that although they understood their concern they did not agree with them. They felt that the present definition provided sufficient clarity and decided to not make any modifications.

One commenter felt that the definition should state that it is a negative value. The drafting team explained that while the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.

Another commenter did not believe that there was sufficient clarity as to the number of observations that would be used to calculate FRM. The drafting team stated that the number of observations would vary from year to year. The basis for determining events is outlined in the Procedure attached to this standard.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. Duke Energy would suggest that the definition read, "The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/0.1Hz."
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
SERC OC Standards Review Group	No	The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. We agree with the Duke Energy suggestion that the definition read, "The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing

Organization	Yes or No	Question 1 Comment
		Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/0.1Hz."
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
PPL NERC Registered Affiliates	No	The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question.
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
BC Hydro	Yes	Additionally, there should be language to clarify that this is a negative value (the same should apply to the definitions of FRO and Frequency Bias). It is fairly obvious that these values should be negative when reading elsewhere in the proposed Standard and its related document but not in their definitions.
Response: While the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.		
Tucson Electric Power	Yes	however, the number of observations to be used in calculating an entity's FRM is not clear.
Response: Thank you for your affirmative response and clarifying comment. The number of observations will vary from year to year. The basis for determining events is outlined in the Procedure attached to this standard.		
Exelon Corporation and its affiliates	Yes	Please see response to question 8. The FRM definition is acceptable within the context of the attachment description; however, without clarifying the terms under which the ERO specifies which events are to be measured, the FRM definition is too variable.
Response: Thank you for your affirmative response and clarifying comment. The criteria used to determine the events to be used are outlined in the Procedure attached to this standard. Please refer to our response to Question #8.		

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	Yes	We believe that refinements to the definition were needed.
Response: Thank you for your affirmative response and clarifying comment.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
NREL Transmission and Grid Integration Group	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
SPP Standards REview Group	Yes	
Edison Electric Institute	Yes	
Arizona Public Service Company	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent	Yes	

Organization	Yes or No	Question 1 Comment
System Operator		
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	Yes	
NV Energy	Yes	
New York Independent System Operator	Yes	
Keen Resources Asia Ltd.	Yes	

Organization	Yes or No	Question 1 Comment
MISO	Yes	
American Electric Power		As provided in question 2 below, AEP does not agree with the definition containing the Frequency Response Sharing Group as this function does not exist at this point in time.

Response: Thank you for your comments. The term Frequency Response Sharing Group is defined at the beginning of the standard. Once this standard is approved by the industry, NERC BOT and FERC the definition will be removed from the standard and added to the NERC Glossary of Terms.

2. **The SDT has created a definition for Frequency Response Sharing Group. The definition is as follows: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members. Do you agree with this definition? If not, please explain in the comment area.**

Summary Consideration: Almost all of the commenters wanted to modify the definition. The drafting team explained that they believed that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.

One commenter did not agree believe it was appropriate to define a new function that was not in the NERC ROP, NERC Statement of Registry Criteria or the NERC Functional Model. The drafting team stated that they had discussed this issue with NERC. NERC staff will add this entity to the registered entity list in the same manner as the existing Reserve Sharing Group. While this is not in the current version available online, NERC will have at least 24 months from the time of regulatory approval to add the entity to the list of registered entities.

Organization	Yes or No	Question 2 Comment
SERC OC Standards Review Group	No	A Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area. We would modify the Duke Energy suggestion to read as follows: "A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources with a goal to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members."
Response: Thank you for your comments. After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
American Electric Power	No	AEP does not necessarily disagree with the words of the definition. However, AEP does

Organization	Yes or No	Question 2 Comment
		not believe it is appropriate to define a new function that is not in the NERC Rules of Procedure, NERC Statement of Registry Criteria, or the NERC Functional Model. It is premature to incorporate this entity without a proposed change to these governing NERC documents.
Response: Thank you for your comments. The drafting team has discussed this issue with NERC. NERC staff will add this entity to the registered entity list in the same manner as the existing Reserve Sharing Group. While not in the current version available online, NERC will have at least 24 months from the time of regulatory approval to add the entity to the list of registered entities.		
Duke Energy	No	As a Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area, Duke Energy would suggest the following definition, "A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources required to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members."
Response: Thank you for your comments. After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Edison Electric Institute	No	EEI does not fully agree with the definition of a "Frequency Response Sharing Group" (FRSG). In the definition offered in the new Standard, it states that the FRSG "collectively maintain, allocate, and supply operating resources". Of the three roles, a balancing authority only maintains load-interchange-generation balance through the allocation of resources. Therefore, EEI suggests that the definition be changed to more appropriately align with the role of a BA, which we believe would be to allocate resources in a manner that effectively allows the sharing of resources necessary to achieve a FRO within the defined sharing group, which might otherwise not be possible or practical by a BA on its own.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This		

Organization	Yes or No	Question 2 Comment
will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
ACES Power Marketing Standards Collaborators	No	We agree that a definition is needed and thank the drafting team for writing one. However, we believe additional refinement of the definition is necessary. Although the definition appears to be written to parallel the Reserve Sharing Group definition, we think the definition needs to be simplified. For one, it encompasses actions that are not necessary. For instance, the proposed definition includes the action to “maintain operating resources”. This could literally include generating plant maintenance. We do not agree that a Frequency Response Sharing Group would jointly perform maintenance on their plants. In fact, since the definition applies to BAs, it is entirely possible within the functional model that the BAs do not even own the plants and could not perform joint maintenance. We assume the purpose of including “maintain” was to recognize that maintenance of generating resources would need to be coordinated to ensure that there was sufficient frequency response reserve. We do not believe this needs to be explicitly identified in the definition. Furthermore, we find the use of “operating resource” as a source of potential confusion. While we understand operating resource is intended to mean a facility that provides the ability to increase or decrease MW output based on the frequency deviation, resource has various meanings throughout the standards and its use here could be confusing and contradictory. For instance, TOP-006-2 R1 discusses transmission resources. Furthermore, if an “operating resource” is capable of increasingor decreasing MW output based on frequency deviation, what is a “resource”? In other words, why is “operating” added to the term “resource”? We think it is best to avoid use of the term operating resource and, thus, recommend changing the definition to: “A group of two or more Balancing Authorities that share frequency response reserves and are required to jointly meet the Frequency Response Obligations of its members.”
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
BC Hydro	Yes	Additionally, there should be language to clarify that the BAs must belong to the same

Organization	Yes or No	Question 2 Comment
		Interconnections to form the FRSG
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
PPL NERC Registered Affiliates	Yes	PPL Affiliates suggest additional detail be added to the definition to ensure the members of the FRSG are all within the same interconnection. The following definition includes the suggested changes: A group whose members consist of two or more Balancing Authorities all within a single interconnection that collectively operate resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Ameren	Yes	The word "jointly" may add confusion and we believe it is unessassry.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
NREL Transmission and Grid Integration Group	Yes	
MRO NSRF	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 2 Comment
Administration		
SPP Standards REview Group	Yes	
Arizona Public Service Company	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 2 Comment
Exelon Corporation and its affiliates	Yes	
NV Energy	Yes	
Tucson Electric Power	Yes	
Keen Resources Asia Ltd.	Yes	
MISO	Yes	
Independent Electricity System Operator		Not Applicable

3. The SDT has added Requirement R3 for entities using variable Frequency Bias. R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

3.1 Less than zero at all times, and

3.3 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/-0.036 Hz.

Summary Consideration: A couple of commenters felt that the intent of the requirement needed to be clarified. The drafting team explained that Requirement R3 is only applicable to a BA using a variable bias and does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.

A few commenters expressed concern with excluding a single BA interconnection from compliance with Requirement R3. The drafting team stated that they had discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.

One commenter disagreed with allowing the use of variable Frequency Bias in a multi-BA interconnection. The drafting team believes that this concern may be better addressed within BAL-001. Variable frequency bias settings allow a Balancing Authority to better match their frequency bias setting in use with the actual frequency response occurring at any instant in time. If it is meeting its FRO for larger frequency deviations and the frequency bias setting in use at that time meets or exceeds its FRO, then the BA is doing its part to support frequency and AGC will not be withdrawing that frequency response.

Another commenter question the periodicity of a BA changing its Frequency Bias Setting to be considered using variable Frequency Bias. They gave an example of an entity changing its FBS monthly. The drafting team stated that they had not defined the periodicity for changing their bias to be variable. The example given would be a form of variable bias and would trigger all rules related to variable bias. Requirement R3 is separate from Requirement R4. Requirement R4 is related

to those entities providing Overlap Regulation Service. It is possible for an entity to provide Overlap Regulation Service and have a variable bias setting therefore an entity may be subject to compliance for both Requirement R3 and Requirement R4.

Organization	Yes or No	Question 3 Comment
American Electric Power	No	AEP believes this question in the comment form is incorrect. It appears that R3 and R4 are inadvertently merged together.
Response: The drafting team is not sure of the point you are trying to make. The question only contains the Requirement R3 from the standard. The drafting team did notice that the numbering of the sub-bullets was incorrect.		
Duke Energy	No	Duke Energy agrees with allowing single-BA Interconnections to utilize a variable Frequency Bias Setting (FBS). Duke Energy disagrees with NERC allowing Balancing Authorities in a multiple-BA Interconnection to change the ACE and bounds by which the Balancing Authorities are measured under BAL-001 and BAL-002 by operating to a variable FBS. It is desired that a Balancing Authority be capable of recognizing the amount of primary response available in real-time operation, such information can be included among other information in the generation control algorithm; however, the obligation to support the Interconnection frequency under the secondary control standards, and the amount provided for any given frequency, should be based on the same criteria across all Balancing Authorities of the same size. Nathan Cohn in his comments on Union Electric's use of a variable FBS expressed similar concern regarding the equitable sharing of the obligation to support Interconnection frequency in a multiple-BA Interconnection. Take for example two Balancing Authorities with equal total generation and load, but one operating under a fixed FBS and the other operating under a variable FBS. To the extent that a Balancing Authority is not providing Frequency Response comparable to its fixed Frequency Bias Setting, its ACE will reflect the difference to be covered with secondary control and the Balancing Authority will be measured in a manner similar to other BAs of its "size" based upon the FBS. To the extent that the other BA using a variable FBS is not providing Frequency Response

Organization	Yes or No	Question 3 Comment
		comparable to what it would be allocated using a fixed FBS, its ACE will not reflect the difference or any further obligation to support Interconnection frequency at that time with secondary control. Duke Energy's concern regarding non-comparable treatment of all BAs is further amplified by the lack of scrutiny placed on the BA algorithm used to determine the real-time variable FBS, to ensure that compliance cannot be gamed by such use.
Response: The drafting team believes that this concern may be better addressed within BAL-001. Variable frequency bias settings allow a Balancing Authority to better match their frequency bias setting in use with the actual frequency response occurring at any instant in time. If it is meeting its FRO for larger frequency deviations and the frequency bias setting in use at that time meets or exceeds its FRO, then the BA is doing its part to support frequency and AGC will not be withdrawing that frequency response.		
Northeast Power Coordinating Council	No	If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then it can be assumed that the BA is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? The intent of this requirement needs to be clarified.
Response: The drafting team is not sure if we understand your first comment. A BA not providing Overlap Regulation Service may or may not be providing Supplemental Regulation Service. Requirement R3 is only applicable to a BA using a variable bias and does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.		
Consolidated Edison Co. of NY, Inc.	No	If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then we can assume it is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? Please clarify the intent of this requirement.
Response: The drafting team is not sure if we understand your first comment. A BA not providing Overlap Regulation Service may or may not be providing Supplemental Regulation Service. Requirement R3 is only applicable to a BA using a variable bias and		

Organization	Yes or No	Question 3 Comment
does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.		
Exelon Corporation and its affiliates	No	Please see response to question 8.
Response: Please refer to the drafting team response to Question #8.		
MRO NSRF	No	The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R3. To ensure a consistent approach in the application of the standard, recommend R3 be revised as follows:(R3). Each Balancing Authority that is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: ...
Response: The drafting team discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.		
MISO	No	We agree with the general obligation but believe that the requirement should apply to single BA Interconnections as well. This is supposed to be a North American standard. What other standards shouldn't apply to a single BA Interconnection? We have the same concern with Requirement 2.
Response: The drafting team discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.		
PJM Interconnection, LLC	No	With what periodicity does a BA's frequency bias setting have to change to be

Organization	Yes or No	Question 3 Comment
		considered variable bias? For example, if a BA changes it's frequency bias setting monthly based on a percentage of each month's forecast or historic load, is this considered variable bias subject to compliance with R3 in lieu of R4?
Response: The drafting team has not defined the periodicity for changing their bias to be variable. The example given would be a form of variable bias and would trigger all rules related to variable bias. Requirement R3 is separate from Requirement R4. Requirement R4 is related to those entities providing Overlap Regulation Service. It is possible for an entity to provide Overlap Regulation Service and have a variable bias setting therefore an entity may be subject to compliance for both Requirement R3 and Requirement R4.		
BC Hydro	Yes	BC Hydro applauds the STD's efforts to recognize a more suitable bound for Variable Frequency Bias settings
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	BPA is responding to 3.1 and 3.2 of R3. The bullets listed in question 3 on the original comment form appear to be for Requirement R4. BPA is in support of R3.1 and R3.2.
Response: Thank you for your affirmative response and clarifying comment.		
Texas Reliability Entity	Yes	It appears that R3.2 is based on the assumption that governor dead-band settings are 0.036 Hz for all interconnections with multiple BAs. While the ERCOT region has a standard 0.036 Hz dead-band specified in the ERCOT Protocols and Operating Guides, we are not sure if this is applicable to the other regions.
Response: Thank you for your affirmative response and clarifying comment. In addition, as to the deadband setting, this number was also considered to be within the frequency deviation range of the event determination criteria as defined in the Procedure document.		
Tucson Electric Power	Yes	N/A

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
SPP Standards REview Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 3 Comment
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator		Not Applicable

4. Based on Industry comments the SDT has modified "Attachment A- Supporting Document" to provide additional clarity. Do you agree with the modifications? If not, what modifications do you disagree with?

Summary Consideration: A few commenters felt that there were requirements stated within Attachment A. The drafting team explained that the requirement stated in the standard was the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.

Several commenters expressed concern over the use of the largest event in the last 10 years for the Eastern Interconnection while all of the other Interconnections used the Category C (N-2). The drafting team stated that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.

A couple of commenters questioned the difference between the present frequency bias of -6,360 MW/0.1 Hz and the proposed of -1,002 MW/0.1 Hz. The drafting team explained that the -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.

A few commenters felt that clarification was need concerning changes in a BAs footprint and changes to the bias setting or FRO. The drafting team felt that this was a problem that would take care of itself. If two BAs change footprint but do not raise the issue the impact is transparent to the Interconnection. If one BA believes that its limits need to be adjusted the process will adjust the limits of both BAs accordingly.

A couple of commenters requested clarity as to how changes to the process in Attachment A would be handled. The drafting team explained that any change to the methodology described in Attachment A would have to go through the Standards Development Process prior to being implemented.

Two commenters felt that there should be an exemption for non-conforming load performing contrary to the performance of conventional load. The drafting team stated that they did not agree that there should be an exemption but has designed the forms to allow for adjustments for non-conforming load. However the BA may find that no adjustment for non-conforming load may be needed due to the measurement over multiple events rather than individual events.

Organization	Yes or No	Question 4 Comment
ACES Power Marketing Standards Collaborators	No	**(1)** Frequency Response Obligation (FRO) is used inconsistently with the proposed definition in the document. The document uses the term “Interconnection Frequency Response Obligation” in many locations. However, FRO specifically is defined as the BA’s “share of the required Frequency Response”. It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection required Frequency Response. **(2)** On page 3 Attachment A states the ERO will post the Frequency Bias Setting for each BA along with their Frequency Response Obligation. Later on the same page, the document states that the BA shall set its Frequency Bias Setting to 100% to 125% of it Frequency Response Measure or Interconnection Minimum. What is the purpose of the ERO determining Frequency Bias Settings if the settings are not going to be used by the BA? What are we missing in the explanation? **(3)** Late on page 3, the document states that BAs are encouraged to notify NERC if load or generation is transferred. Section 4(a) on page 8 of the Rules of Procedure Appendix 5A - Organization Registration and Certification Manual indicates that changes to a Registered Entity’s footprint actually triggers a potential certification audit. Since BAs are required to be certified and moving generation or load from the metered boundaries of one BA to another BA would represent a change in footprint, we suggest removing the word “encouraged” and stating affirmatively that BAs must notify NERC of such changes and referencing the appropriate section of the Rules of Procedure. Otherwise, BAs may not realize notification is actually required.
Response: (1) The drafting team believes the IFRO and FRO terms are used appropriately in Attachment A. Interconnection Frequency Response Obligation is not defined in the standard nor is it a performance obligation. The drafting team has clarified Attachment A in instances when using the terms to address your comments.		

Organization	Yes or No	Question 4 Comment
(2) The ERO is not determining the FBS but is only validating the FBS provided by the BA on FRS Form 1. **(3) The SDT believes these are two coordinated but separate processes. If the Rules of Procedure apply, as worded this document provides the avenue to make the necessary changes to Frequency Bias Setting.**		
Consolidated Edison Co. of NY, Inc.	No	**(1)** This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the "target contingency criteria"), etc. **(2)** Of value to entities would be a sample calculation. **(3)** "The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years". Why aren't all interconnections using the same design contingency design basis? **(4)** The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Can the DT explain why this attachment refers to an Interconnection frequency response obligation of -1,002MW/.1Hz. This is a significant difference.
Response: (1) As stated in Attachment A these terms are defined in the Procedure. The drafting team clarified the use of multiple terms of "resource contingency criteria" throughout both Attachment A and the Procedure documents. **(2) The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.** **(3) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.** **(4) The -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.**		

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is under the impression that there are some requirements, which though not explicitly stated, are implied in Attachment A. AEP feels strongly that these "sub-requirements" should be clarified and contained within the body of the requirements of the standard.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM.		
Duke Energy	No	As indicated in our comments in the past, Duke Energy is certain that as the Interconnection Frequency Bias Setting (FBS) is set closer to the actual Frequency Response in a multi-BA Interconnection, most BAs will be challenged in meeting CPS2, while CPS1 and the proposed Balancing Authority ACE Limit (BAAL) will be more achieveable bounds, and in some cases CPS1 performance will improve. Though probably most of the BAs may welcome a FBS set as high in magnitude as allowed to address the potential compliance risk, there are some which may desire to set their FBS closer to their required minimum allocation rather than have to take on a larger obligation in frequency support under the secondary control measures. Duke Energy believes that this proposed standard should incent BAs to provide more than their share of Frequency Response to the Interconnection and allow that good performance to be recognized; however the requirements described in Attachment A for determining the minimum Frequency Bias Setting (FBS), which requires that the FBS be set no lower in magnitude than the FRM, will leave certain over-performing BAs with no choice but to reduce their actual Frequency Response (still well-above their FRO) if they want to operate with a FBS set closer to the Interconnection Minimum allocation and be relieved of the associated increased obligation for frequency support under the secondary control measures. The FBS is embedded within the secondary control measures of CPS1, CPS2 and the draft Balancing Authority ACE Limit (BAAL). Comparable treatment of similarly-sized BAs (based upon the FRO allocation) is only possible if all BAs are provided the same minimum FBS requirement. To the extent that a BA provides more than its share of response to events, it's over-performance will only

Organization	Yes or No	Question 4 Comment
		be recognized if its ACE is allowed to reflect a FBS comparable to its peers, allowing its over-performance to be reflected in ACE in support of bringing frequency closer to 60 Hz. Generation control algorithms implemented today to optimize CPS1 will allow non-zero ACE when in support Interconnection frequency within bounds determined by the BA - there should be no concern of "response withdrawal" with such algorithms in place, the BA will simply get credit for such performance. As depicted in the current document, the over-performing BA would be required to set its minimum FBS at its FRM (or greater in magnitude), taking away what should be considered over-performance, erasing it in ACE, and turning it into an obligation under the secondary control measures. Based upon the draft, the only way that the BA could be treated comparably to other similarly sized BAs held only to operating to the Interconnection Minimum allocation, would be to reduce its actual response in FRM to a value less in magnitude than its Interconnection Minimum allocation. Duke Energy believes that BAs should be incented to provide more than their share of Frequency Response, and be given the opportunity to report performance on a basis comparable to similar-sized BAs. Our opinion is that Attachment A ensures that the Interconnection Frequency Bias Setting will remain at some margin above the actual Interconnection Frequency Response in magnitude - the reliability of the Interconnection will not be at risk by allowing over-performing BAs to operate and report performance on a comparable basis to other similarly-sized BAs based upon the Interconnection Minimum allocation if they choose to do so - to that extent, Duke Energy suggests that the language on page 3 be changed to:"A BA using a fixed Frequency Bias Setting may set its Frequency Bias Setting to any number the BA chooses up to 125% of its Frequency Response Measure as calculated on FRS Form 1, but no less in magnitude than its Interconnection Minimum allocation as determined by the ERO."Regarding the argument which could be offered that a larger FBS in magnitude will also allow wider bounds for control performance, Duke Energy agrees that a large portion of the BA operation will be around 60 Hz where such a benefit could be realized, however it would also come at the cost of a larger obligation than other comparably-sized BAs in sustained support of frequency during the more critical times of significant deviation from 60 Hz where the BA's compliance could be at risk. Below 59.95 Hz in the Eastern Interconnection (the

Organization	Yes or No	Question 4 Comment
		Frequency Trigger Limit under BAAL), the additional MWs needed to be compliant for any given frequency are greater than the MWs of imbalance allowed by the larger BAAL bound - comparably-sized BAs will not be comparably judged if the standard forces over-performing BAs to assume a larger FBS (in magnitude) than their peers - that should be the decision of the BA. We believe that the proposed language above will create the proper incentive for a Balancing Authority to provide more than its minimum allocation of Frequency Response, and allow it to choose if it wants to make that performance part of a larger FBS (in magnitude), knowing the associated risks and benefits of that decision.Duke Energy supports this standard allowing for Frequency Response Sharing Groups, however the requirements and supporting documents need to clearly allow the FRSG to be treated no differently than if it was a Balancing Authority and shield the participating BAs from compliance scrutiny when all scrutiny should be placed on the FRSG performance as a whole. At the top of Page 3, the standard attachment allows the FRSG to “calculate a group NIA and measure the group response to all events in the reporting year on a single FRS Form 1”, however at the bottom of page 3, the standard attachment still requires the FRSG BAs to individually fill out Form 1 and Form 2 for the purposes of determining the minimum Frequency Bias Setting. Duke Energy believes that the standard language in Attachment A, and the supporting form(s), should allow the FRSG, if it chooses, to also report the split of the group FRM which the BAs will use to individually determine their Frequency Bias Setting, rather than require each BA in an FRSG to still maintain Form 1 and Form 2 data. Form 1 could be modified for the FRSG to report the group’s FRM along with the split of the FRM among the members, and another form could be developed for each FRSG BA to fill out, replicating only the section of Form 1 (column S) where each BA could provide values for its FRM allocation, its desired FBS, its minimum FBS allocation, and so on.

Response: The drafting team has chosen to reduce the minimum Frequency Bias Settings for individual BAs on a controlled basis on each Interconnection. Your suggestion would eliminate the ability of the drafting team to coordinate the reduction of the minimum Frequency Bias Settings for the BAs. Other commenters have stated that they disagree with reducing the minimum

Organization	Yes or No	Question 4 Comment
Frequency Bias Setting. The drafting team is attempting to balance between the two positions stated in previous postings. **The drafting team understands your concern regarding the treatment of FRSG and the minimum Frequency Bias Setting. However, the drafting team believes that this allocation of Frequency Bias among the FRSG members on a basis different from the measured response could be detrimental to reliability under system separation conditions. Future consideration of this issue may be possible once additional information is available.**		
Independent Electricity System Operator	No	As indicated in our previous comments, the status of Attachment A is unclear. It is a mixture of requirements, criteria, process and guideline. Making a direct reference in the standard's requirements (R1 and R2) makes Attachment A as part of the requirement and hence is enforceable, but it contains process and guideline information that is not subject to assessment. On the other hand, the absence of a Measure to assess adherence to the criteria and process suggests that Attachment A is not enforceable. It is this ambiguity that makes it difficult for the industry to assess the extent to which they must follow the process. Again, we urge the SDT to keep only the criteria/process parts that must be adhered to in Attachment A, and extract the remaining parts and place them in a guideline document, or an appendix.In addition, the Responsible Entities are required to submit Form 1 and Form 2, but such requirements are not written explicitly as "shall", and are imbedded in the Attachement whose mandatory status is unclear. This makes the standard very confusing from an Responsible Entity's obligation and compliance perspective.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.		
BC Hydro	No	BC Hydro agrees with the principles outlined in the Attachment A but has some concerns as follows: 1.Attachment A is no longer recognized as one of the associated document of the proposed Standard in its currently posted version. We believe this was removed by mistake.

Organization	Yes or No	Question 4 Comment
		2.There is no clarity as to how certain factors used in determining the Interconnection FRO such as CCADJ, CBR and BC'ADJ were determined. There is no apparent provision to re-assess any potential changes to these factors over the future years. If such provision is needed or has been provided then consideration should be given to averaging the adjustment over a longer duration (i.e., using the average of the factor observed over a number of years rather than just the year being assessed). 3.The method used for the allocation of the Interconnection FRO to BAs seems to not recognize the fact that frequency response from Load is much less than frequency response from Generation of an equal MW size. 4.If this Attachment A is considered an integral part of the standard then there should be some enforceable measures to ensure applicable entities adhering to the prescribed time line.
Response: **(1) The drafting team disagrees that Attachment A is not one of the associated documents of the standard. It is included by reference in Requirements R1 and R2 and will be attached to the standard upon final approval.** **(2) If the data inputs change then the number will change but the methodology used to calculate the number cannot change without going through the standards process.** **(3) The drafting team agrees with your conclusion. The source of the Frequency Response is not related to the distribution of the obligation.** **(4) The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.**		
Bonneville Power Administration	No	BPA does not agree with the methodology in Attachment A. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.

Organization	Yes or No	Question 4 Comment
Response: Please refer to our response to Question #6 and our responses to your comments submitted on 12/8/11.		
Exelon Corporation and its affiliates	No	Exelon is troubled by the approach of having requirements that rely so heavily on the attachment to the standard. The use of both of the documents is required to be compliant and this makes it difficult to determine what the obligations are and increases the chance for error in interpretation. The suggested changes below in response to question 8 take information from the Attachment and establish requirements so that an entity does not have to go back and forth between the two documents to identify its obligations. Attachment A should then be modified to include examples of Forms 1 and 2 and instructions for completing the form for Balancing Authorities and Frequency Response Sharing Groups.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure. **The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.**		
SERC OC Standards Review Group	No	It is important for NERC to monitor the interaction between the deployment of this standard and its impact on CPS1, CPS2, and BAAL. If performance in the CPS criteria is degraded, there should be a halt in the reduction of the minimum bias setting allowed. There is also concern that we are providing the correct incentives to the entities to provide the appropriate amount of frequency response. We also suggest that clarification be made so that changes in the BA's footprint that would necessitate changes in the bias setting or the FRO be permanent changes, not just temporary. It is unclear how performance would be measured for a BA versus a frequency response sharing group.

Organization	Yes or No	Question 4 Comment
Response: The minimum is not required to be reduced but is allowed to be reduced if no significant impacts are seen on CPS1, CPS2 and BAAL. **The drafting team agrees that temporary changes will not apply in this case. It is a problem that will take care of itself. If two BAs change footprint but do not raise the issue the impact is transparent to the Interconnection. If one BA believes that its limits need to be adjusted the process will adjust the limits of both BAs accordingly.** **The Background Document and Attachment A explain how a FRSG would report. The FRS Forms allow BAs and RSGs to account for contributions from either.**		
PPL NERC Registered Affiliates	No	The NERC posting did not include a redline to Attachment A, therefore, it is not clear what modifications were made. However, there are several modifications that would add clarity to the attachment. The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question, additionally, the following issues should be addressed: In Attachment A, page 3 and elsewhere, clarify that temporary or small transfers of load or generation between BAs do not require notification to the ERO or changes to the FBS or CPS limits. In Attachment A, page 4, a BA should be allowed to be exempt from evaluation any single frequency event where non-conforming load performs contrary to the performance of conventional load (ie. during a frequency decline, the non-conforming load simultaneously increases significantly). By nature, non-conforming load is totally unpredictable, changes quickly, and fluctuates widely. Other than interruption, the BA has no control over the actions of such loads nor can the BA predict or assume any “normal” action by a non-conforming load during a frequency disturbance event. Setting a limit on the number of events that a BA could exempt (regardless of the reason) from FR evaluation in any given year would be more fair and effective in evaluating a BA’s frequency response performance.
Response: Please refer to our response to the SERC OC Standards Review Group.		

Organization	Yes or No	Question 4 Comment
The drafting team does not agree that there should be an exemption but has designed the forms to allow for adjustments for non-conforming load. However the BA may find that no adjustment for non-conforming load may be needed due to the measurement over multiple events rather than individual events.		
Kansas City Power & Light	No	The Standard proposes a calculation that overstates the frequency response obligation (FRO) for Balancing Authorities.
Response: The drafting team disagrees with your comment. However, the drafting team cannot provide any detail due to the lack of details in your comment.		
Arizona Public Service Company	No	The supporting document on the standards page does not provide information on CB Ratio and why it is used. It significantly increases FRO and should be justified based upon strong technical basis and actual experience. (Please also see AZPS response to question 6, The Frequency Response Initiative Report should be on the Standards page).
Response: The rationale can be found beginning on page 14 of the Background document and page 49 of the FRI report. **Please refer to our response for Question #6.**		
PJM Interconnection, LLC	No	The target contingency protection criterion for the Eastern Interconnection is the largest event in the last 10 years (believed to be a 2007 event) which is inconsistent with the other Interconnections. Is periodic review required for this criteria? Will this criteria be revised after the referenced event is older than 10 years? Are the other three interconnection's target contingency protection criteria subject to revision if they experience an event larger than a category C? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. What are the procedural requirements for revising Attachment A? This BA is concerned that the procedure for revising Attachment A is undefined and

Organization	Yes or No	Question 4 Comment
		that, for example, the IFRO could be increased absent the formal standard revision process, increasing a BA's FRO and subsequently increasing a BA's compliance risk without providing BA's the opportunity to review, comment, and ballot.Related to the previous comment/question, how often are the statistically derived values in Table 1 subject to a required update? For example, the Eastern Interconnection is adjusted due to observed primary frequency response withdrawal ('lazy L' characteristic). The other Interconnections are adjusted for observed differences between point C and point B. As the frequency response characteristics of any Interconnection change, is Table 1 subject to required analysis and revision? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. Attachment A indicates that a BA may exclude an event from annual Form 1 FRM evaluation only if its tie-line or frequency data is corrupt or unavailable. This exempts numerous scenarios that could result in a poor response score due to system variations. These could include, but are not limited to, changing energy schedules, changes in load, and AGC driving units up or down due to the ACE value at the time of the frequency event. This subjects the BA to undue compliance risk even though the BA may have adequate frequency responsive resources at the time. This BA suggests that the FRSDT adopt language (and Form 2 functionality) that allows the exclusion of events that are skewed by these types of situations. Attachment A and Forms 1 & 2 specify that 20 to 52 seconds will be used as the post-event B point average for FRM determination. The number of fast responding resources will increase as the technology for batteries, flywheels, and frequency controlled demand side devices moves forward over time. The 20 to 52 second interval does not adequately incentivize the devopment of these technologies.
Response: The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details		

Organization	Yes or No	Question 4 Comment
are provided on pages 52 through 55 of the Frequency Response Initiative paper. **As the model for the EI is improved and information and experience is gained under this standard the answer to your question will be determined through an open and inclusive process.** **If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process.** **The drafting team does not agree that there should be an exemption but has designed the forms to allow for certain adjustments. In addition, the methodology recommended utilizing the median addresses the concerns related to a single event occurrence. Ultimately the BA may find that no adjustment may be needed due to the measurement over multiple events rather than individual events.** **This standard was not intended to provide incentives for the development of new technologies. It is intended to provide for the reliable operation of the Bulk Electric System.**		
Northeast Power Coordinating Council	No	This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the “target contingency criteria”), etc. A sample calculation would be of value to entities. “The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years”. All interconnections should be using the same design basis contingency. The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Why does this attachment refer to an Interconnection frequency response obligation of -1,002MW/.1Hz.? This is a significant difference.
Response: As stated in Attachment A these terms are defined in the Procedure. The drafting team clarified the use of multiple terms of “resource contingency criteria” throughout both Attachment A and the Procedure documents. **The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.** **The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages**		

Organization	Yes or No	Question 4 Comment
52 through 55 of the Frequency Response Initiative paper. **The -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.**		
Ameren	No	We disagree on having different methodologies for determining the targets, and would like clarity added for when those targets may change, such as what will happen after the largestest event in the last 10 years rolls off the books for the EI?
Response: The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper. **If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process.** **As the model for the EI is improved and information and experience is gained under this standard the answer to your question will be determined through an open and inclusive process.**		
Manitoba Hydro	Yes	(1) Page 2, Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting: States that the ERO is responsible for “annually assigning an FRO and Frequency Bias Setting to each BA.” No mention is made of FRSGs. (2) Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an FRSG to comply versus a BA. In particular, compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an FRSG and that in such cases the FRSG has the same responsibilities as each BA (that is a participant in the FRSG). (3)Attachment A refers to an FRSG calculating FRM, but the standard does not.

Organization	Yes or No	Question 4 Comment
Response: 1) - The FRSG FRO is a summation of its members' FROs. **2) & 3) -The drafting team believes that it is clearly stated for a FRSG compliance with R1. The Requirement reads "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation."**		
Texas Reliability Entity	Yes	1. The calculation for the FRO for ERCOT includes a credit of 1400 MW for load resources. 1400 MW is currently the maximum amount of LR that can be procured through the ERCOT ancillary service process. There can be periods during the day where 1400 MW was not procured or is not available (It was noted during the summer of 2012 that on some days, only 900 MW of LR was available through the ancillary service process). Should the calculated IFRO (-286 MW per 0.1 Hz) be modified to account for this variation? 2. Background Document says: "Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation: o Largest category C loss-of-resource (N-2) event o Largest total generating plant with common voltage switchyard o Largest loss of generation in the interconnection in the last 10 years" For ERCOT, the largest loss of generation in the last 10 years was over 3400 MW, and does not match the 2750 MW (N-2) value used for the IFRO calculation.
Response: **(1) The process used to determine the IFRO has been vetted through multiple forums. The drafting team feels that the proposed calculation is appropriate for the standard at this time. As experience is gained through the implementation of this standard, the calculation will be reviewed and any adjustments will be addressed through an open and inclusive process.** **(2) The results for the current Texas Interconnection model represent observed response adequately so the recommended Resource Contingency Criteria for ERCOT is the Category C N-2 event. For further details related to the full determination,**		

Organization	Yes or No	Question 4 Comment
please refer to the Frequency Response Initiative paper.		
SPP Standards REview Group	Yes	Delete the 2nd 'that' in the 2nd bullet at the top of page 3.
Response: Thank you for the comment. The drafting team has made the correction.		
Xcel Energy	Yes	It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the document should be modified to clearly identify where 'steps/actions' are needed from responsible parties, whether that be the ERO or BA/FRSG.
Response: If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process. **Please refer to the "timeline" on page #6 of Attachment A as this clearly provides for who has responsibility for each step in the process.**		
NextEra Energy	Yes	NextEra Energy does not support the changes made. It is concerned that certian changes were made to help some large East coast entities that could not comply at the expense of the FRCC region. Specifically, now on page 3 of Attachment A 4th paragraph from the bottom the statement is made " sets its frequency bias to the greater of". We believe that this must be changed to either Statement 1 " Any number the BA chooses between 100% etc"Or Statement 2 " Interconnection minimum as determined by the ERO" Without this change, NextEra beleives the FRCC will be unfiarly treated relative to others on the Eastern Interconnection. The technical reasons for this is concern was explained during the Standard Drafting Team meetings. In addition, the ERO limit which is set at 0.9% of load should be changed to read within 0.8 or 0.9% of peak load based on the BA's choice. Also, see page 7 of the Procedure document and compare to page 1 of Attachment A.

Organization	Yes or No	Question 4 Comment
		The formulae abbreviations for the variables in the Procedure are not likewise abbreviated in Attachment A. For example, “Credit for LR” on Attachment A is “CLR” in the Procedure, but it requires cross checking each document to figure this out. Or CBr in Attachment A, Table 1 is represented as DFCBR in the Procedure, Page 7. Since the same variables are being described, these should be represented the same way in both documents throughout. 2. Similarly, is “IFRO” in Table 1 of Attachment A the same as “FROInt” of the equation that follows on page 2? The same abbreviation should be used to represent this variable. The documents should be revised in general along these lines for all terms. 3. In Procedure document, page 5, paragraph 3 it should read “Table 2”, not “1”. 4. In the Procedure, it would be good to show Table 1 and Table 2 as Table 1 of Attachment A (i.e. use table lines and borders). 5. At least in the first usage, ERO in the Procedure document should be spelled out as “Electric Reliability Organization (ERO)”. 6. In Table 1 of Attachment A, the two footnotes preceded by asterisks (single and double on page 2) should be connected to the table by adding a single superscripted asterisk to the Eastern UFLS value of 59.5, and a double superscripted asterisk to the ERCOT LR value of 1,400.

Response:

(1) The drafting team does not believe any BAs were favored over other BAs. However the drafting team is unclear as to your expressed concerns related to FRCC. In direct communications with FRCC they concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.
The drafting team does not agree with the recommended wording change for the bias setting because it would essentially remove the Interconnection minimum FBS. The drafting team does not agree that we are mixing terms between the Procedure and Attachment A. The drafting team uses CBR and DFCBR in both documents defining two different variables. The drafting team clarified CLR.

Organization	Yes or No	Question 4 Comment
(2) The drafting team clarified IFRO/FRO in the documents. **(3) Thank you. The drafting team has corrected this in the document.** **(4) The drafting team thanks you for your comment. However, the majority of the industry does not support your suggested modification. Therefore, the drafting team will leave the tables as shown.** **(5) The drafting team changed ERO to Electric Reliability Organization as per your suggestion.** **(6) Thank you. The drafting team has made the changes.**		
NREL Transmission and Grid Integration Group	Yes	Table 1: CB_r units should be unitless, CB'adj should be Hz.
Response: Thank you for the comment. The drafting team has made these changes.		
NV Energy	Yes	This document is improved, and satisfactorily addresses comments from the prior posting.
Response: Thank you for the comment.		
New York Independent System Operator	Yes	With a new process we are concerned that the interconnection minimum will initially move from 1.0% to 0.9%.
Response: Thank you for your comment. The new process moves the minimum from 1.0% to 0.9%.		
MRO NSRF	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	

Organization	Yes or No	Question 4 Comment
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Tucson Electric Power	Yes	
Keen Resources Asia Ltd.	Yes	
MISO	Yes	
Puget Sound Energy		In reviewing the Consideration of Comments document, it is clear that the standard drafting team does not wish for the administrative elements of Attachment A to become items addressed during compliance evaluations ("There is no intent to require filing on a certain date and to have the BA prove to the auditor that a filing was made on that date." This quote appears at several places in the Consideration of Comments documents, but first at page 113). However, because Attachment A is referenced in the standard, its provisions, including the timing table, are all mandatory and enforceable. This result is emphasized by the language of requirement R1, which states that entities "...shall achieve an annual Frequency Response Measure (FRM) as calculated and reported in accordance with Attachment A...." This language means that a failure to file a document on a date specified in the attachment would be a potential compliance violation. Because Attachment A is mandatory and enforceable, the standard drafting team should carefully review its provisions and clarify which elements are requirements and which elements are background statements or guidance. In addition, the use of additional headings and section numbers would add in clarifying the document (for example, at the top of page 3, there is a discussion of how an FRSG would calculate its FRM; however, there is an entire section beginning on

Organization	Yes or No	Question 4 Comment
		page 4 addressing FRM where that discussion should instead appear).
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.		

5. **The SDT has moved a portion of the material located in Attachment A and all of the material located in "Attachment B- Process for Adjusting Bias Setting Floor" into a new document "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard". The SDT created this document to assign tasks to the ERO and provide instructions for the ERO to follow when carrying them out under the BAL-003-1 standard. Do you agree that the ERO should perform these tasks and that this document provides sufficient detail for the ERO to do it under the BAL-003-1 standard? If not, what needs to be added to the document?".**

Summary Consideration: Several commenters requested clarity on how modifications to the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard would be made. The drafting team explained that the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" was not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.

A couple of commenters questioned how events would be excluded, specifically with regards to during ramping periods. The drafting team stated that all events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.

A few commenters did not understand why the frequency criteria are different for each Interconnection. The drafting team explained that the frequency criteria was different for each interconnection because the frequency used to measure frequency response is interconnection dependent and varies differently for each interconnection. Larger interconnections have greater frequency response and as a consequence smaller frequency deviations for events of the size typically experienced.

One or two commenters questioned whether certain events should always be included in the evaluation process. The drafting team stated that based on event evaluation by this drafting team, it has been determined that it is impossible to require certain events to be included. This is the reason that the drafting team has developed the Event Selection Criteria.

Organization	Yes or No	Question 5 Comment
Keen Resources Asia Ltd.	No	As a professionally trained published statistical expert never compensated by any balloting participant, I consider event selection criterion 7 to be unacceptable because it violates the fundamental statistical procedure of sampling statistical data "as is" and not pre-selecting the data (to fit some preferred even-distribution over time) and therefore biasing it before applying any statistical procedure to the data. Event criterion 6 is also unacceptable for being an an "ad hoc" explicit exclusion, from the definition of the frequency response being measured, of response to frequency events that occur during a specific kind of scheduled generation and load changes. Said exclusion needs to be written into the definition of the Frequency Response that is being measured. It is procedurally improper and unacceptable to bias the sampling procedure by explicit exclusion of data as an alternative to redefining the thing being sampled. In that case it's not generic Frequency Response that is being sampled, but some specific Frequency-Response-less-Response-to-Excluded-Events that is being measured. It is non-transparent and subterfuge to avoid instead accordingy reworking/narrowing the definition of Frequency Response, especially as said reworking requires a clear technical justification that is absent from this standard, and modifying the existing NERC Glossary definition of Frequency Response which Criterion 6 therefore stands in flat violation of.

Response: Criterion 7 is included in the Event Selection Criteria because the drafting team considers it very important to be able to select and finalize events for analysis quarterly so that the BAs can evaluate their performance as the measurement year unfolds. This necessarily requires minimal criteria to insure that this selection and finalization process can be completed quarterly. The drafting team recognizes that this finalization may have some effect on the sampling, but values the quarterly selection and finalization more than the pure statistical sampling theory. This is a trade-off that the drafting team has chosen to make. Once several years of a regular disparity between seasons of the year were established in terms of number of events in a season, the industry could propose modifying the Standard at that time to adjust Criterion 7 accordingly.

Criterion 6 is included because historic data indicate that the periods within 5 minutes of the top of the hour have shown to have

Organization	Yes or No	Question 5 Comment
higher frequency variability than other periods in the hour. Statistical analysis presented in the FRI Report indicates that pre-disturbance frequency is a significant contributor to the variability of frequency response. The drafting team has chosen to allow the exclusion of events close to the top of the hour when other acceptable events are available until analysis is done of whether these periods have a statistically different frequency response and therefore introduce bias. Meanwhile, as Balancing Authorities are moving toward quarter-hourly scheduling, the higher top-of-the-hour frequency variability prompting the need and application of Criterion 6 is expected to disappear. Therefore, while your recommended alternative of changing the NERC definition of Frequency Response may be statistically correct, from a practical perspective it would likely prove to be a needless chore and to yield a needlessly complicated definition only to have to be changed back again.		
Southern Company	No	Attachment A states that Form 1 is posted annually. The ERO support document selects events annually. The timing for the two documents needs to be aligned so that the set of selected events does not change from quarter to quarter. (If three events are selected for the first quarter those same events will be a sub-set of the 20 events selected for the annual compliance calculations.)
Response: Attachment A indicates that Form 1 with the events from the previous quarter is posted on May 10th, August 10th, November 10th and the second business day in February. It is the intent of the standard that events once posted will be included in the FRM analysis.		
BC Hydro	No	BC Hydro agrees in principle that the ERO should perform these tasks related to BAL-003-1 but has the following concerns: 1. There is no clear indication whether the Interconnection FRO will be calculated every year, and if yes, how each of the factors involved will be determined. 2. It is not clear whether data gathered in these procedures are only for the determination of annual FRO and FBS, or also to determine whether the BA or the FRSG was in compliance to BAL-003-1 for the assessed year. Since the ERO in this Document seems to be the NERC Resources Subcommittee and its Frequency Work Group, we think this fact should be made clear. The Background document should also be reviewed to ensure its alignment in this regard.

Organization	Yes or No	Question 5 Comment
Response: The drafting team has chosen to use the methods presented in the FRI Report to determine the values presented in Table 1 of Attachment A to determine the Interconnection FRO. If the method of calculation by the ERO or the base starting values used to determine the IFRO change (i.e. Resource Contingency Criteria or Prevailing UFLS First Step), then those changes will be subject to the standards process to accept those changes. If the statistical determinates used in the method change (i.e. Starting Frequency, CC_{ADJ}, CB_R, BC'_{ADJ}, and Credit for LR) or the data used to allocate the IFRO among the BAs (i.e. FERC Form 714 data) changes, the new values will be implemented without being subject to the standards process. The data gathered for the FRO calculation is not compliance related. The calculation of FBS is also not compliance related. However, assuming the information is entered into FRS Form 1 correctly then the FBS number will be used by an auditor to determine compliance with Requirement R2. The drafting team has been instructed by NERC to refer to all NERC entities (i.e. Frequency Working Group, Resources Subcommittee, etc) as the ERO.		
Bonneville Power Administration	No	BPA does not agree with the methodologies outlined in Attachment B. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf
Response: Please refer to our response to your comment for Question #6 and our responses to your comments dated 12/8/11.		
Kansas City Power & Light	No	Criteria 3 - Why are frequency thresholds different between regions when generator governor reaction is supposed to be the same between regions? Criteria 5 - What is the reasoning that multiple events that are not stabilized within 18 seconds not being considered? Criteria 6 - How are "changes in scheduled interchange" or load change determined in regions with interconnections with multiple BAs with different time zones?
Response: The frequency criteria is different for each interconnection because the frequency used to measure frequency response is interconnection dependent and varies differently for each interconnection. Larger interconnections have greater frequency response and as a consequence smaller frequency deviations for events of the size typically experienced.		

Organization	Yes or No	Question 5 Comment
The standardized method used to measure frequency response will not work correctly for events that have not stabilized within 18 seconds. **This determination will be made by the ERO (presently the Frequency Working Group).** **All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.**		
Duke Energy	No	Duke Energy agrees with allowing the ERO to perform this function, however the industry needs some assurance that this Procedure cannot be changed outside of the Standards Process for approval by the industry. In the sixth line of the third paragraph on page 5, the statement should reference Table 2. Page 5 reads as if the BAs will submit their data based upon Form 1 which includes an adjustment to the Interconnection peak load (initially 0.9), and then the ERO will determine whether the Interconnection minimum FBS is still more than 20% above the measured response - if so, the minimum FBS will be adjusted, requiring the BAs to reassess their new minimum FBS based upon a different factor, and decide whether to use that value or choose a value up to 125% of their FRM, resulting in another iteration of values being submitted to the ERO. If the ERO is going to do an independent assessment of Interconnection Frequency Response to the events, on an annual basis prior to gathering data from the BAs, the ERO could compare the total FBS being used by the BAs against the estimated Frequency Response over that period to determine if an adjustment is warranted, and then the ERO could include the appropriate adjustment factor (0.9, 0.8, etc..) in Form 1 for the BAs to use. If the ERO is not going to estimate the Frequency Response aside from the BAs, multiple iterations will be likely. Duke Energy suggests the following language to cover the point above: “On an annual basis, the ERO will review the Interconnection total minimum Frequency Bias Setting for the prior period and compare it against the Interconnection’s total natural Frequency Response determined for that period. If an Interconnection’s total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection’s total natural

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>Frequency Response by more (in absolute value) than 0.2 percentage points of the Interconnection non-coincident peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of Interconnection non-coincident peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response. The ERO will include the adjustment factor in the Interconnection Form 1 used by the Balancing Authorities for the calculation of the new minimum Frequency Bias Setting. The Form 1 information from the Balancing Authorities will be gathered by the ERO in coordination with the regions of each Interconnection to determine the final Interconnection Frequency Bias Setting for the next period.”</td></tr>
<tr><td colspan="3">Response: The “Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard” is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC’s commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.

The reference has been changed from Table 1 to Table 2. Thank you for your comment.

The review of the information provided by the BAs discussed in the Procedure document will take a significant amount of time. Therefore, the change to the Interconnection Minimum Frequency Bias Setting will occur on the subsequent year’s Form 1. This will eliminate the risk of multiple iterations and allow sufficient time for the ERO to consult with the regions as indicated in the Procedure. The drafting team has included clarifying language in the document.</td></tr>
<tr><td>Tucson Electric Power</td><td>No</td><td>I think it should be more clear or better defined that an interconnection does have some input into what events are selected.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Each interconnection has a representative on the Frequency Working Group that performs the selection of events.		
Exelon Corporation and its affiliates	No	Please see response to question 8.
Response: Thank you for your comment. Please see response to Question 8.		
PJM Interconnection, LLC	No	The Procedure indicates that events that occur when 'large interchange schedule ramping or load change is happening' and 'events occurring within 5 minutes of the top of the hour' should be excluded from consideration. Since interchange schedule ramping and load change occurs at the BA level, this BA believes that the Procedure allows for the selection of events that occur when a BA is experiencing these conditions but Attachment A does not allow for exemption of these events. Also, the Procedure specifies that events that occur at the top of the hour be excluded, if other qualifying events exist, but this does not take into consideration energy markets that allow for sub-hourly schedule changes (e.g. 15 minutes) and the BA is not permitted to exempt these events on Form 1 subjecting the BA to undue compliance risks.
Response: Thank you for your comment. All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.		
Texas Reliability Entity	Yes	1. Event Selection Criteria Item 2: Should certain events require mandatory inclusion for FRM calculation (i.e. DCS events)? 2. Event Selection Criteria Item 6: We disagree with the way this is worded. If a unit trips during this time, as it often can, measured frequency response needs to occur. We understand that the results are impacted by the grid condition and perhaps that is why the SDT decided to exclude the issue. Need to define what is intended by a "large"

Organization	Yes or No	Question 5 Comment
		interchange ramp schedule or load change. May also want to consider changing the language from "will be excluded from consideration" to "MAY be excluded from consideration".
Response: Thank you for your comment. Based on event evaluation by this drafting team, it has been determined that it is impossible to require certain events to be included. This is the reason that the drafting team has developed the Event Selection Criteria. **The drafting team wrote the criteria to allow flexibility for any change that significantly impacts frequency.** **The drafting team looked at the language and determined that the present language provides greater clarity. The "will be excluded" is followed by "…if other acceptable frequency excursion events from the same quarter are available." Therefore, it is not a mandatory exclusion.**		
Edison Electric Institute	Yes	EEI supports the ERO's role as defined in the procedure but is concerned that the procedure, unlike approved NERC standards, is unbounded by the current rules for developing standards. For that reason, EEI recommends that the procedure become more formalized and integrated into the standard as an addendum thereby avoiding any Industry concerns that future modification might occur outside the approved processes
Response: Thank you for your comment. The "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.		
ACES Power Marketing	Yes	Overall, we agree. However, we suggest the document clarify that the ERO shall

Organization	Yes or No	Question 5 Comment
Standards Collaborators		perform these tasks in coordination with the Resources Subcommittee. It consists of industry experts that can be an extra resource to NERC. Furthermore, NERC staff working with the Resources Subcommittee will provide additional transparency to the process.
Response: Thank you for your comment. The drafting team has been instructed by NERC to refer to all NERC entities (i.e. Frequency Working Group, Resources Subcommittee, etc) as the ERO.		
MISO	Yes	The first hyperlink on page 3 of the Procedure for ERO Support does not work.
Response: Thank you for your comment. The drafting team has corrected this.		
Xcel Energy	YES	It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the doucment should be modified to clearly identify where 'steps/actions' are needed from repsonsible parties, whether that be the ERO or BA/FRSG.
Response: Thank you for your comment. The "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid	Yes	

Organization	Yes or No	Question 5 Comment
Integration Group		
SPP Standards REview Group	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
NV Energy	Yes	
New York Independent System Operator	Yes	
MRO NSRF		MRO NSRF AGREES

6. **The SDT is now using the method detailed in the Frequency Response Initiative Report dated September 30, 2012 to calculate the Interconnection Frequency Response Obligation. Do you agree that this method provides for the proper amount of Frequency Response? If not, what specifically needs to be changed?**

Summary Consideration: Many of the commenters requested clarification on how changes to the methodology defined in Attachment A could be modified. The drafting team explained that Attachment A was part of the standard and as such is subject to the NERC standards process for making any changes.

Several commenters questioned the use of the largest event in the last 10 years for the Eastern Interconnection. The drafting team stated that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the SDT has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.

One commenter wanted a method to discount outliers. The drafting team explained that this was one of the reasons that they had chosen the median as the appropriate measure for FRM. The benefit of using the median of at least 20 events per year helps to minimize the impact of outliers.

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	BPA does not have specific changes to the methodology to suggest, however, a methodology that arrives at a negative 840 MW per tenth Hz for WECC is obviously under-calculating the frequency bias obligation. Currently WECC has an interconnection bias of over 2000 MW / 0.1Hz and with this bias the frequency is steady state following point B on the frequency response curve. BPA would expect to see frequency decline after point B if the FBO is lowered by almost 60%. BPA also must reiterate that there is still a problem with the method used for modifying the FBO and frequency bias for Balancing Authorities. A high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events chosen by

Organization	Yes or No	Question 6 Comment
		the ERO.
Response: After review of comments, the drafting team feels confident with the current method of calculating Frequency Response Obligation as outlined in the Frequency Response Initiative report. This standard requires minimum bias setting not to be less than 0.9% of the non-coincidental peak load for a multi-BA interconnection. This will ensure that minimum bias settings will be based on Interconnection's non-coincidental peak load rather than biased toward low-performer. The minimum Frequency Bias settings requirement are outlined in Table 2 of "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" **The drafting team points out that there is not a Frequency Bias obligation and that the currently measured response for the Western Interconnection is approximately -1200 MW/0.1 Hz. This number is above, but much closer to the required level of -840 MW/0.1 Hz under this standard.**		
Tucson Electric Power	No	I believe that the frequency bias obligation of the Western Interconnection is understated.
Response: The drafting team points out that there is not a Frequency Bias obligation and that the currently measured response for the Western Interconnection is approximately -1200 MW/0.1 Hz. This number is above, but much closer to the required level of -840 MW/0.1 Hz under this standard.		
Duke Energy	No	Similar to our earlier concern, the industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. Duke Energy does not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards		

Organization	Yes or No	Question 6 Comment
process manual for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the SDT has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
New York Independent System Operator	No	The drafting team should consider some method for discounting outliers, that may not be explainable.
Response: Thank you for your comment. All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.		
Southern Company	No	The industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. We do not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an**		

Organization	Yes or No	Question 6 Comment
increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.		
PPL NERC Registered Affiliates	No	The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question
Response: The Attachment A is part of the standard and as such is subject to the NERC standards process for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
Keen Resources Asia Ltd.	No	This question is falsely worded. The SDT is specifically NOT using the method detailed in the Frequency Response Initiative Report dated September 30, 2012. So the term "this method" is practically meaningless in this question because it is not clear if it means "the SDT's method" or "the FRI's method". The Background Document specifically states on page 29: "The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered." What needs to be changed, besides properly wording this question? The FRI method of linear regression should be adopted, and the SDT method of median should be rejected, in the standard to change the first sentence of this question into a true statement from a false statement and to, in answer to the question, provide for the proper amount of

Organization	Yes or No	Question 6 Comment
		Frequency Response.
Response: Thank you for your comments. The drafting team disagrees that the methodology for calculating the IFRO used in this standard is different than that detailed in the FRI Report. The drafting team considered replacing median with linear regression but chose to use the median because of its better resiliency to data quality problems found in the Actual Net Interchange data used in the frequency-response calculation.		
SERC OC Standards Review Group	No	We believe the industry needs some assurance that the calculation of the interconnection FRO cannot be changed without rigorous review and input from the industry. In addition the clarification should be made how the one in ten year loss for the Eastern Interconnection (4500 MW) would change after 10 years. Would the same methodology be used or would the largest Category C (n-2) be used?
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process manual for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
Arizona Public Service Company	NO	1. The Frequency Response initiative report should be added to the standard as an appendix. It is not clear where to find this report. 2. The jusitification for dividing delta frequency with C to B ratio is not adequate and not clear.
Response: Thank you for your comment. 1) The drafting team disagrees that the FRI Report should be attached to this standard as an appendix. We do agree that it should be easier to locate. **2) Please refer to the FRI Report for the reasoning you request.**		
Edison Electric Institute	Yes	EEI finds the method to be acceptable but as mentioned in our response to question

Organization	Yes or No	Question 6 Comment
		No. 5 (above), we believe that the procedure should be more formally documented as an addendum. Such a change would ensure that the document would remain unchanged outside of the approved standards making process. Additionally, EEI does not support using 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the results is an allocation which we believe is acceptable. In the future, should the SDT decide to use 59.7 Hz as the basis for the FRO, than it will need to follow a methodology similar to the other interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process manual for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
ACES Power Marketing Standards Collaborators	Yes	We agree that this method will provide sufficient frequency response. However, we believe Interconnection Frequency Response Obligation is used inconsistentently with the definition of Frequency Response Obligation as documented in our response to other comments.
Response: Please refer to our responses to your other comments.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
SPP Standards REview	Yes	

Organization	Yes or No	Question 6 Comment
Group		
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	
MISO	Yes	
MRO NSRF		MRO NSRF AGREES

7. Based on Industry comments received the SDT made significant clarifying modifications to the Background Document. Do you agree that this document provides sufficient information to justify the rationale used by the SDT in developing the draft standard and provides the industry with sufficient understanding of the issues being addressed by the standard?

Summary Consideration: Several of the commenters questioned why the formula for FRO was missing. The drafting team explained that this was a problem incurred during the conversion to a pdf file. Once the problem was recognized by NERC, it was immediately fixed during the posting.

A couple of commenters felt that there should be discussion in the Background Document concerning "inertial response". The drafting team stated that they saw a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.

A few of the commenters questioned the use of the largest event in the last 10 years as the criteria for the Eastern Interconnection. The drafting team explained that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.

Organization	Yes or No	Question 7 Comment
ACES Power Marketing Standards Collaborators	No	(1) The formula for calculating Frequency Response Obligation appears to be missing on page 23. (2) We are confused by the varying sample rates for the different scan rates in the Definitions of Frequency Values for Frequency Response Calculation table on page 13. It would appear that the time range of values for the average B value varies more than necessary by scan rate. For example, for 2-second scan rates, sampling would start at 20 seconds and end at 52 seconds. However, for the 4-second scan rates, sampling

Organization	Yes or No	Question 7 Comment
		starts at 24 seconds and ends at 48 seconds. Why would it not also cover 20 and 52 seconds for a 4-second scan rate?
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. (2) The SDT has corrected the table.		
Bonneville Power Administration	No	BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.
Response: Thank you for your comment. Please refer to our response to your comments dated 12/8/11.		
Keen Resources Asia Ltd.	No	See reply to Question 6. Also, the Background Document is seriously deficient in the discussion of inertial response and therefore how imbalances "cause" frequency deviation. The Background Document is overflowing in discussion of how frequency deviation causes frequency response. In other words, the Background Document is "reactive" and not "proactive". The Background Document lacks any discussion of the internal dynamics of rotating machines, beginning with any definition of what Inertial Response is. Inertial Response is the instantaneous power produced by the lag ("inertia") in the ability of the generator's rotor to slow down to the frequency of the magnetic field in the generator's fixed stator whose frequency is instantaneously lowered by a change in phase angle between voltage and current that is due to a sudden loss of interconnected generation to meet load. Adjustments by voltage response within milliseconds and near the location of the loss are sometimes possible to avert rapid spread of a loss to the frequency of the entire interconnection, and constitute the ongoing work of the Phasor Project long ago initiated by the DOE in the persistent absence of NERC interest or work in this area. NERC and drafting team members under advisement by NERC staff studiously resisted so much as any mention of frequency deviation causation in discussions or in the Background Document. An

Organization	Yes or No	Question 7 Comment
		inexplicable technical Cold War and Berlin Wall built in the 1970s and today separating the DOE Phasor Project from NERC Frequency Response standard development and NERC's so-called Frequency Response "Initiative" needs to be ended and torn down. My document http://www.robertblohm.com/Inertia.doc provides missing technical support and explanation for graphs 1-7 on pages 4-10 of the Background Document, on the basis of an exact understanding of Inertial Response.
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		
Northeast Power Coordinating Council	No	While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of “primary frequency response”.
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		
Consolidated Edison Co. of NY, Inc.	No	While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of “primary frequency response”.
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		

Organization	Yes or No	Question 7 Comment
PPL NERC Registered Affiliates	Yes	The PPL Affiliates applaud the SDT for developing this technical justification document.
Response: Thank you for your comment.		
Duke Energy	Yes	Though Duke Energy does not agree with some of the points in the Background Document, it does justify the rationale used by the SDT. Additional comments: at the top of page 23, it states that the basic Frequency Response Obligation is based on non-coincident peak load and generation data reported in FERC Form 714, however the actual calculation is missing and should be based upon the reported MWh, not the peak load as stated. At the bottom of page 23, it states that Attachment A proposes the three options for event criteria, however doesn't clarify why it was chosen that the Eastern Interconnection would be held to the largest event over the last 10 years, while others will be based upon the largest category C loss-of-resource (N-2) event.
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. **(2) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.**		
SERC OC Standards Review Group	Yes	We agree with the Duke Energy comments on this question.
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. **(2) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on**		

Organization	Yes or No	Question 7 Comment
pages 52 through 55 of the Frequency Response Initiative paper.		
SPP Standards REview Group	Yes	We like the document and feel that it provides a primer on the frequency response standard.The following are typos in and suggested corrections to the document:-The blue lines referenced in the paragraph under Figure 2 on page 14 are green (A) and red (B).-Insert an 'a' in the 3rd line of the 2nd paragraph in the Sustained Response section on page 19 between 'provides' and 'greater'.-Insert a 'for' in the 2nd line of the 1st paragraph on page 21 between 'resource' and 'all'.-Change 'provide' to 'provided' in the 3rd line from the bottom line of the 1st paragraph in the Single Event Frequency Response Data section on page 24.-Change the 'east' to 'Eastern Interconnection' in the 4th line of the 1st paragraph in the Median as the Standard's Measure of Balancing Authority Performance section on page 27. -Delete the 'put' in the 3rd bullet on page 29. Also, replace the 'put' in the 5th bullet with 'gave'.
Response: Thank you for your affirmative response and clarifying comment. The errors you mentioned have been corrected.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	
Tucson Electric Power	Yes	
BC Hydro	Yes	
MISO	Yes	
MRO NSRF		MRO NSRF AGREES

8. **If you are not in support of this draft standard, what modifications do you believe need to be made in order for you to support the standard? Please list the issues and your proposed solution to the issue.**

Summary Consideration: A couple of commenters expressed concern with the fact that the onus for Frequency Response was being put on the BAs who do not own or operate the generators. The drafting team explained that they had heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

A couple of commenters stated that they thought the standard was confusing. The drafting team stated that they appreciated their concern that the standard is confusing, but the drafting team believed that the proposed standard is as clear as possible while covering all of the issues involved and that based on comments received the industry was not in agreement.

One or two commenters requested clarity on how modifications to the Attachment A could be made and if the FRS Forms 1 and 2 had to be used. The drafting team explained that Attachment A was part of the standard and would have to use the Standard Development Process to make any modifications. The drafting team also stated that the FRS Forms were required to be used in the reporting.

A couple of commenters questioned the use of the Background Document. The drafting team explained that the Background Document was only intended to be used for education and training similar to other training references in the NERC Operating Manual.

Organization	Yes or No	Question 8 Comment
ACES Power Marketing Standards Collaborators	No	(1) We believe that the drafting team work has demonstrated that the standard is unnecessary. The data presented in the posting shows that all of the interconnections easily exceed the required Frequency Response necessary to avoid actuating UFLS relays. Since one of the main purposes of the standard is to provide sufficient Frequency Response, it would seem the purpose is already met without implementing and enforceable standard. So why is a standard needed to compel required Frequency Response if it is already provided? (2) Even though we believe the supporting data for the posting demonstrates the standard is unnecessary, we understand NERC is required by a FERC directive to provide a standard. Given this requirement, we do believe the drafting team has largely provided a reasonable standard and supporting documents that only require a few additional adjustments (see our comments in other questions for these adjustments) to finalize the standard. As a result, we will likely end up supporting the standard once these final adjustments are made.
Response: Thank you for your comment. We agree that the standard meets the primary directive to provide Frequency Response. This standard will set a backstop to assure that Frequency Response will not decline past a "point of no return" **For issues raised in other questions please refer to our response to those questions.**		
Independent Electricity	No	a. We do not support R2 as drafted, specifically the phrase "until directed to change by the ERO". We do not agree that the ERO has any authority to "direct" a BA or FRSG, or

Organization	Yes or No	Question 8 Comment
System Operator		any responsible entities, to make changes to the Frequency Bias Setting or take any operating or operations planning actions. We suggest to replace the word “directed” with “requested”. b. In R2, the words “subject to” can be interpreted differently. We suggest to replace them with “in accordance with” to parallel the intent as conveyed in R1. c. We are still concerned with the status of Attachment A, as indicated in our comments submitted under Q4 - that it is unclear if the materials in Attachment A must be adhered to or not. A standard should not have an attachment whose enforcement status is unclear as part of a requirement. d. FRS Forms 1 and 2 are referenced in Attachment 1, which itself has an unclear status on measurability and enforceability. It is also unclear if FRS Forms 1 and 2 must be used to submit the requested data. Collectively, Attachment 1, FRS Form 1 and Form 2 make the standard very confusing as to which parts must be complied with. Much better clarity is needed to clearly convey the standard ‘s requirements that are measurable, enforceable and must be complied with.
Response: Thank you for your comments, **a) The drafting team believes that the term “direct” is less ambiguous. The drafting team believes that using the term “request” could leave the impression that the action is optional.** **b) The drafting team has adopted your suggested language.** **c) Please refer to the drafting team response to Question #4.** **d) The Attachment is mentioned in the standard requirements and is therefore enforceable. Since the FRS Forms are discussed in the Attachment then they must be used in the calculation process.**		
Bonneville Power Administration	No	BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA’s extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. Please refer to the drafting team response to your comments submitted on 12/8/11.		
Exelon Corporation and its affiliates	No	Exelon checked "no" because it does not support the current draft standard. Exelon's position is that efforts to modify frequency monitoring and control should be directed at the existing standards. Since Frequency Bias is already a component of ACE, and ACE performance is tracked by both CPS 1 and CPS 2, it seems evident that NERC already has in place mechanisms for evaluating frequency response. NERC already has in place mechanisms for ensuring sustained frequency response during a contingency, through the Disturbance Control Standard (DCS) and its requirement for the contingent Balancing Authority to deploy resources. Under the current BAL-003-0.1b language, Balancing Authorities are given a consistent means for determining frequency bias, via the minimum requirement of 1% peak generation or 1% peak load. Together with the above references to existing CPS 1 performance measurements, current standards meet the objectives outlined in BAL-003-1. This proposed draft BAL-003-1 complicates the setting of Frequency Bias and attempts to go beyond that purpose into frequency response performance, without clear rules for how to perform. Exelon is also concerned with moving this standard forward while there is an ongoing field trial that could impact whether this standard should be put into place. For example, waivers are in place for CPS 2 for participating Balancing Authorities and there is ongoing effort with the BAAL field trial set of standards that will establish performance metrics around frequency control. As an alternate approach to waiting to move forward on the standard, Exelon recommends the following BAL-003-1 Requirement language: R1. The ERO shall identify up to five [5] system frequency events in each Interconnection that will be included in the Form 1 and 2 data requests for Balancing Authorities by April 30th each year. R2. Each Balancing Authority shall submit the following data to the ERO annually by July 15: R2.1 The total annual net output of generating plants inside the Balancing

Organization	Yes or No	Question 8 Comment
		Authority Area. R2.2 The total annual load with losses inside the Balancing Authority Area. R3. Each Balancing Authority shall calculate its Frequency Response Measure using Forms 1 and 2 as posted by the ERO. (See Attachment A_Form 1 and Form 2) R4. Each Balancing Authority or Frequency Response Sharing Group shall submit Forms 1 and 2 to contacts designated by the ERO before the expiration of ERO established deadlines, which shall be no earlier than 30 days after posting of Forms 1 and 2. R5. The ERO shall post the following information: R5.1. Each Interconnection's Frequency Response Obligation R5.2 Each Balancing Authorities Frequency Response Obligation R5.3 Each Balancing Authorities Frequency Bias Setting R6. Each Balancing Authority shall implement in its ACE equation its ERO established Frequency Bias Setting during the ERO established three-day implementation period. No further adjustments can be implemented outside of the parameters established below in the upcoming year unless a Balancing Authority coordinates with the Regional Entity and the affected Balancing Authorities. R6.1 A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value): R6.1.1. The number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1. R6.1.2. The Balancing Authorities share of the Interconnection Minimum as determined by the ERO. R6.2 A Balancing Authority using a variable Frequency Bias Setting shall maintain a setting that is:

Organization	Yes or No	Question 8 Comment
		R6.2.1 Less than zero at all times, and R6.2.2 Equal to or greater in magnitude than its Frequency Response Obligations when Frequency varies from 60 Hz by more than +/-0.036 Hz. R7. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a FRSG shall monitor its Frequency Response Obligation and work with generating facilities or demand response resources to provide sufficient Frequency Response to meet the Frequency Response Obligation assigned by the ERO. R8. Each Balancing Authority that adds or removes generation or load, including through the use of dynamic transfers, shall notify the ERO to ensure that any needed adjustments to the Interconnection Frequency Response Obligation or Balancing Authority Frequency Response Obligation and Bias can be calculated. R8.1. The ERO shall notify all affected Balancing Authorities of modifications to the Frequency Response Obligation due to the addition or removal of generation or load. R9. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent of the sum of the Frequency Bias Setting as communicated by the ERO for the participating Balancing Authorities.
Response: Thank you for your comment. ACE, CPS1, CPS2, BAAL and DCS are all standards that measure Secondary Control actions. The inclusion of the Frequency Bias Setting in ACE and these standards make them blind to Primary Frequency Control and thus incapable of helping with the evaluation of Frequency Response (Primary Frequency Control). R1 sets clear rules with respect to how much Frequency Response is required from each BA through the Frequency Response Obligation (FRO) and Frequency Response Measure (FRM). The BAAL Field Trial is investigating issues associated with Secondary Frequency Control only and is not impacted by and has no impact on Primary Frequency Control and BAL-003. The drafting team has considered the suggestions contained in the requirements suggested and has explained in the Background document the reasons for writing the		

Organization	Yes or No	Question 8 Comment
requirements and measures as contained in the draft BAL-003-1.		
Duke Energy	No	Given the FERC deadline approaching for NERC to deliver a Frequency Response standard, Duke Energy supports the adoption of this standard with some reservations. We believe that the proposed standard addresses the FERC directive to NERC, however it also introduces some longer-term issues related to secondary control and related costs that may have not been anticipated by the FERC. To that point, Duke Energy believes that if this standard is adopted, the industry will have the time and opportunity through the NERC standards development process to mitigate some of the concerns presented in our comments."
Response: Thank you for your affirmative response and clarifying comment. The drafting team agrees that there could be some impact on other standards but the implementation period will allow for time to adjust and learn		
Tucson Electric Power	No	I feel that a BA's frequency bias for the upcoming year should not be related to present performance. A BA may have a good response one year and not good response another year and therefore the threshold keeps moving around. I feel it should be related to BA size and therefore somewhat standardized. E.g. a high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events chosen by the ERO.
Response: Thank you for your comment. The drafting team believes that control and frequency performance improve if the Bias Setting and the BA's Frequency Response are as closely matched as possible. Low performing BAs will still have to provide the Interconnection minimum Bias Setting. In an unlikely case where a high performing BA has an internal change that markedly reduces their Frequency Response, there are provisions in the standard's supporting document to accommodate an intra-year change in its Bias Setting.		
New York Independent System Operator	No	In general we support the work of the DT, and the proposal to measure the systems response to frequency events, along with the method to determine the FRO. My

Organization	Yes or No	Question 8 Comment
		outstanding concern is with enforcement on an entity that does not own the resources that provides the frequency response or the lack of obligation for the entity with the information to provide to the BA to make the assessment of expected frequency response. BA's should at a minimum be given assurance that resources will provide data that BA's could use to forecast frequency response and take corrective actions.

Response: Thank you for your comment. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year.

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).

Organization	Yes or No	Question 8 Comment
Tri-State Generation and Transmission Assn., Inc.	No	It is our opinion that there has not been enough justification to merit creating a new standard. If additional justification is provided then frequency responsive reserves should be a subset of spinning reserves much like spinning reserves are a subset of operating reserves.
Response: Thank you for your comment. This standard will set a backstop to assure that Frequency Response will not decline past a "point of no return" **This standard does not prescribe a method to provide Frequency Response but does provide for measuring that Frequency Response is delivered.** **Spinning reserve is outside the scope of the industry approved SAR.**		
Puget Sound Energy	No	See comment in response to question 4 above for a discussion of Attachment A concerns. Appendix 1 of the Frequency Response Standard Background Document contains a discussion about why the use of net actual interchange to calculate an entity's Frequency Response Measure might introduce inaccuracies into that calculation. That discussion ends with the following statement: "The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error." Based on these statements, it is very difficult to support the standard's approach to calculating the Frequency Response Measure.At Puget Sound Energy (PSE), though, we believe that there is another factor to add to the "operational cacophony" listed in Appendix 1. PSE is a comparatively small BA with limited internal generation. We are embedded between two of the largest energy exporters in the Western Interconnection and, when there is a frequency event, their response flows through PSE's system. As a result, PSE will experience transmission losses associated with the two BAs' frequency response as it flows through our system. When PSE's frequency response is measured using net actual interchange, these losses obscure, at least in part, our system's

Organization	Yes or No	Question 8 Comment
		frequency response. As a result, we ask the standard drafting team to consider specifying a process that would allow us to propose and use an equivalent measure of frequency response. For example, while we understand the concerns and difficulties associated with measuring frequency response at the generator as the default measure for all BAs, in our case, a choice to use that measurement option might prove to be a more-feasible way to comply with the standard.
Response: Thank you for your comment. Please refer to our response to your comments on Question #4. **Analysis of Field trial data has not shown that this has been a problem.** **The spreadsheets have been designed to allow for adjustment for dynamically scheduled resources located in another BA.**		
PJM Interconnection, LLC	No	See previous comments. Also, this standard should be applicable to GOP's as well as BA's with, at a minimum, the following requirements added: Each GOP shall follow all directives of it's Balancing Authority pertaining to frequency responsive operation, including but not limited to the status, droop & deadband settings of their governors. Each GOP shall provide to their BA the status and droop & deadband settings of their governors, and headroom available to respond to frequency deviations, as requested.
Response: Thank you for your comment. MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. **Generator verification standards (MOD 27) are scheduled to be revised. The drafting team believes that this will address your second concern**		
PPL NERC Registered	No	The PPL Affiliates are concerned that the document referred to "Attachment A" is

Organization	Yes or No	Question 8 Comment
Affiliates		directly referenced in the proposed standard's requirements but not actually attached to the standard itself as Attachment A. Therefore, it is not clear how the proposed document could be modified in the future. Having such material incorporated into a standard takes away from the open and transparent stakeholder drive process.
Response: Thank you for your comment. The attachment is mentioned in the requirement within the standard and therefore becomes a part of the standard. Any modifications needing to be made to the attachment will have to use the Standards Process.		
Consolidated Edison Co. of NY, Inc.	No	The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially Attachment A.
Response: Thank you for your comment. The drafting team appreciates your concern that the standard is confusing, but the drafting team believes that the proposed standard is as clear as possible while covering all of the issues involved. **The drafting team will either develop training materials to provide better understanding for both the FRM and FBS calculations or recommend to the NERC Resources Subcommittee to develop said materials.**		
Northeast Power Coordinating Council	No	The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand, and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially in Attachment A.
Response: Thank you for your comment. The drafting team appreciates your concern that the standard is confusing, but the drafting team believes that the proposed standard is as clear as possible while covering all of the issues involved. **The drafting team will either develop training materials to provide better understanding for both the FRM and FBS calculations or recommend to the NERC Resources Subcommittee to develop said materials.**		
Kansas City Power & Light	No	The Standard does not consider instances for smaller BAs that operate generation for peak conditions and acquire energy for most of the operating year.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. The drafting team is unsure of your precise question. However, if your question concerns meeting your performance obligation year around, then the process does allow for mechanisms for a BA to obtain Frequency Response from external resources		
NV Energy	No	While I support the concept of a Frequency Response Standard with minimum performance obligations, this Standard places the entire obligation for performance on the Balancing Authority (and Frequency Reserve Sharing Group). Requirements R2-R4 are properly assigned to the BA, as this is the entity that is responsible for the configuration and parameters in the ACE equation, including the provision of a frequency bias setting. Requirement 1, however, is a performance requirement over which the BA in the Functional Model has virtually no control or ability to influence. Only a Generator Owner or Generator Operator is in a position of control over the performance under this requirement through the operational control and configuration of the responding generating units. In most BA's, the host BA entity also owns a fair amount, even a vast majority in many cases, of the generation within the BA. However, even in the event that the host BA owned 100% of the generation within its metered boundary, it is the action of the entity exercising its GO/GOP function that impacts the frequency response performance within the Balancing Area. Assignment of R1 to the BA is inappropriate from the standpoint that reliability requirements are to be assigned to the Reliability Functions who are capable of causing compliance to occur. A BA has limited ability to influence the outcome of the R1 performance metric. This is unlike other BA-assigned requirements, such as those related to DCS or CPS compliance. For those, the BA does have considerable influence regarding the curtailment of transactions to restore ACE, the direction of plant loading so as to distribute operating reserve, etc. In contrast, performance under this proposed R1 of BAL-003-1 is dependent upon the actions of the GO/GOP in such things as governor settings, generator control system configuration and other operatinal or maintenance activities conducted at the generating plant site. For this reason, it is inappropriate to assign this performance requirement to the BA. Rather, the requirements should be allocated among the GO/GOP's of the on-line generation in some fashion.In further support of

Organization	Yes or No	Question 8 Comment
		this notion, refer to the NERC Functional Model, where it is provided that one of the tasks for Generator Operation is to support Interconnection frequency.

Response: Thank you for your comment. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year.

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).

Organization	Yes or No	Question 8 Comment
Arizona Public Service	NO	1. Either do not use C to B Ratio or provide adequate rational for using it. It appears to

Organization	Yes or No	Question 8 Comment
Company		make FRO unnecessarily too conservative and is not justified based upon experience. 2. The VRF is too complicated and hard to understand. It must be either simplified or should be followed by example. 3. The Frequency Response Obligation Methodology on Page 7 of "Procedure" does not show any formula (it is blank).
Response: Thank you for your comment. 1) The rationale can be found beginning on page 14 of the Background document and page 49 of the FRI report. 2) The drafting team is assuming you meant the VSLs. The VSL attempts to correct the VRF based on the BA's size and its impact on the interconnection. 3) This was corrected during the posting. The problem occurred when the Word document was translated to a pdf file.		
Energy Mark, Inc.	Yes	Although I am in favor of using linear regression to determine the FRM, the standard using Median is better than not having a standard.
Response: Thank you for your comment. The drafting team thanks you for your affirmative response and clarifying comment.		
Southern Company	Yes	Please refer to comments for question 9.
Response: The drafting team thanks you for your affirmative response and clarifying comment. Please refer to our response for Question #9.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 8 Comment
California Independent System Operator	Yes	
Ameren	Yes	
MISO	Yes	
AESO		1. The AESO disagrees with using a non-authoritative background document that has definitions/description of terms used in the reliability standard. It is the opinion of the AESO that these definitions/descriptions need to be authoritative. 2. The AESO has previously submitted comments to the SDT that for the purpose of the FRM calculation, BAs should be able to exclude or include events based on specific conditions or consideration, such as data quality or event suitability (e.g. BA separation from the Interconnection). The revisions made by the SDT do not enable the inclusion of other relevant events in the FRM calcualtion by a BA. The AESO would like to to see these type of events to be permitted in the FRM calculation by a BA.
Response: Thank you for your comment. 1) The Background Document is intended for education and training similar to the other training references in the NERC Operating Manual. **The drafting team believes that any new definitions that are located in the standard will ultimately be placed in the NERC glossary.** **2) The drafting team believes that your concern will be addressed through the process since:** **a) separation events would not be selected,** **b) the median will exclude the outlier situations, and** **c) If the data is corrupted, the FRS Forms allows for exclusion of that event.**		
Public Service Enterprise Group		PSEG entities will vote “Negative” on the standard until this Project 2007-12 achieves the following: 1. It coordinates with Project 2010-14.1 Phase 1 of Balancing Authority Reliability-

Organization	Yes or No	Question 8 Comment
		based Controls Reserves, specifically BAL-012-1, regarding (a) definitions and (b) requirements that address frequency response in both standards. a. Definitions that need to be coordinated: BAL-003-2 - "Frequency Response Obligation" and BAL-012-1 - "Frequency Responsive Reserve." b. Requirements that need to be coordinated: i. BAL-003-1, per R1, states "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." ii. BAL-012 requires BAs to have sufficient Frequency Responsive Reserves per R6, which requires BAs to "assess, on at least an hourly basis, that it has sufficient Regulating Reserve, Contingency Reserve, and Frequency Responsive Reserve to meet its reserve plan(s) to ensure reliable operation of the Bulk Electric System." For Frequency Responsive Reserves, R3 in BAL-012-1 requires BAs to develop an annual plan for these reserves.BAs should not be subject to duplicative requirements for frequency response requirements in different standards that are underdevelopment. Only one standard needs to define the frequency response requirements for BAs (we suggest that be BAL-003-1), although other standards, such as BAL-012-1, may reference that obligation. However, this decision should be made by consensus between the two SDTs. 2. It coordinates with Project 2010-14.1 Phase 1 of Balancing Authority Reliability-

Organization	Yes or No	Question 8 Comment
		based Controls Reserves, specifically BAL-012-1, to develop an application guide that would be attached to one of the standards and that could be referenced by each standard. The application guide would include: a. A hypothetical implementation plan for a BA that demonstrates how the BA may meet its Frequency Response Obligation or Frequency Responsive Reserve prior to an event. This is a technical issue and should not be confused with the institutional issue in #3 below. b. An explanation of the relationship between Regulating Reserve, Contingency Reserve, and Frequency Responsive Reserve contained in BAL-012-1 so that potential double counting (and whether that is proper of improper), is addressed. 3. Project 2007-12's "Frequency Response Standard Background Document" dated October, 2012 lists several methods of obtaining Frequency Response. Most of those are extracted below. We have provided questions and commentary that we ask the team to address. a. "Regulation services." This is addressed in BAL-001-0.1a. The purpose of this standard is "To maintain Interconnection STEADY-STATE FREQUENCY within defined limits by balancing real power demand and supply in real-time. How is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) b. "Through a tariff (e.g. Frequency Response and regulation service). " The team is advised to review the actual pro-forma OATT schedule for Schedule 3 "Regulation and Frequency Response Service" which is specifically limited to services providers that are "capable of providing this service as necessary to follow the moment-by-moment changes in load." Again, how is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) c. "From generators through an interconnection agreement." The FERC's pro-

Organization	Yes or No	Question 8 Comment
		forma Standard Large Generator Interconnection Agreement (LGIA) per Order 2003 contains no requirement for generators to provide Frequency Response service, and we are not aware on ANY interconnection agreement that does. We ask that the team point to ANY interconnection agreement with such a requirement. Modification of an interconnection agreement to incorporate such a requirement would require the consent of both parties. d. “Contract with an internal resource or loads.”Since Frequency Response service would likely be considered as a necessary service to provide Transmission Service under an OATT, it would require a tariff. What existing tariff applies in the U.S.?The “methods” above that the team has listed have the factual errors described. The standard BAL-003-1 cannot be implemented until the necessary tariffs are developed that permit BAs and FRSGs to contract for Frequency Response services. Once that is done, BAL-003-1 can dictate the performance requirements of a BA or FRSG. o For context, FERC OATT schedules relevant to Frequency Response DO NOT set performance requirements. Schedule 3 (Regulation and Frequency Response Service) sets forth a tariff for the service, while BAL-001-0.1a sets forth performance requirements in aggregate for a BA or RSG. Likewise, Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service) set tariffs for both services, while BAL-002-1 sets performance requirement. Without an OATT schedule for Frequency Response service, BAs and FRSGs will have no means to contract with generators or loads to provide Frequency Response per BAL-003-1. The team should address this concern.

Response: Thank you for your comment. There is significant coordination between the two drafting teams and this coordination will continue as all standards referenced are posted for comment.

With regard to double jeopardy, both drafting teams have been coordinating to ensure this does not occur.

We believe it is important from a reliability perspective to have a performance based standard. The ultimate need for tariff changes, interconnection agree, etc will be based on a BA’s need to meet the standard.

Organization	Yes or No	Question 8 Comment
Within the measures for R1 and the discussions in the Background document, the drafting team believes that FERC and the industry will be able to develop the changes to tariffs to address your concerns with the BA contracting with sources of Frequency Response to meet its FRO. The BA is also responsible for dispatch levels of resources that provide Frequency Response. Now that Frequency Response has been clearly defined and is able to be measured, sources of Frequency Response for delivery of the service can be developed by the industry. Once both BAL-003-1 and BAL-012-1 have passed, the drafting team believes it would then be an appropriate time for the members of the two drafting teams to develop an application guide.		
American Electric Power		There is no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some performance measures in that regard.This revision adds new performance measure responsibilities on the BA who likely has no direct control over every resource affecting their performance within their footprint. We are not necessarily challenging the performance measures themselves, nor their underlying objectives, however AEP views this as a gap in responsibilities which potentially effects reliability. AEP suggests that GOPs be considered as part of this standard so that their performance can be factored into the process to meet the performance objectives.
Response: Thank you for your comments. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver). There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VARs. To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?		

Organization	Yes or No	Question 8 Comment
MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place. Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).		
SPP Standards REview Group		We support the standard as proposed.
Response: The drafting team thanks you for your support.		

9. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1.**

Summary Consideration: A couple of commenter disagreed with the VSLs for Requirement R1. The drafting team explained that the VSLs were a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation.

One commenter felt that there was an inconsistency between Requirement R4 and Requirement R1 and Attachment A concerning how a BA providing Overlap Regulation Services would calculate its FBS. The drafting team disagreed with their comment. Under the two options in R4 the BAs must still comply with the minimum setting requirements through the calculations performed under R2. In your example, if both BAs turned in FRS Form 1 showing a FBS based on the 100% - 125% minimum these two numbers would be added together for compliance with R4.

One commenter felt that the definition should state that it is a negative value. The drafting team explained that while the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.

One commenter disagreed with putting the onus on the BA for providing Frequency Response. The drafting team The drafting team explained that they had heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

One commenter questioned how the event selection process would work. The drafting team stated that the event selection process was outline in the Procedure for ERO Support of the Frequency Response and Frequency Bias Setting Standard.

Organization	Question 9 Comment
ACES Power Marketing Standards Collaborators	(1) Please strike “that is a member of a multiple BA Interconnection” in R2 and R3. The language makes the requirements difficult to read. We understand this is trying to clarify that these requirements should not apply to BAs such as ERCOT since changing its Frequency Bias Setting does not need to be coordinated with other BAs among other issues, and we do not have an issue with this intent. However, there is an easier way to address this issue without creating a confusing requirement. The SDT should include seeking a variance for the ERCOT area in conjunction with developing the standard. (2) Please strike “in order to represent the Frequency Bias Setting for the combined Balancing Authority Area” in Requirement R4 as it is superfluous and incorrect. First, the two bullets provide the necessary information making the statement unnecessary. Second, the BA Areas are not combined into a single BA Area as implied with the statement “combined Balancing Authority Area”. They are still in fact two distinct BA Areas.

Organization	Question 9 Comment
	(3) The data retention period for R1, R2, R3, and R4 is not consistent with the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention section states that data shall be kept for the current calendar year plus the three previous calendar years. This could be up to four years which exceeds the BA audit period of three years. It is unnecessary for a BA to maintain evidence that was already verified in a prior audit. We recommend changing the evidence retention period to three years. (4) Has the drafting team coordinated the addition of the Frequency Response Sharing Group (FRSG) with the Functional Model Working Group and the NERC staff responsible for organizational registration? If not, please do so as NERC will need to be willing to register entities as a FRSG if it is to be utilized. Furthermore, the Functional Model Working Group should document the purpose and intent of the FRSG .(5) We disagree with the VSLs for R1. The VSLs are structured such that a BA's or FRSG's violation is dependent upon the rest of the interconnection to determine the severity level of the violation. If the BAs collectively fail to achieve the Interconnection Frequency Response obligation, a 2% violation of the Frequency Response Measure jumps from a Lower VSL to a High VSL. This should never be the case. No violation by a registered entity should become potentially more or less severe based on the violation of another entity. We encourage the drafting team to work with NERC Legal department in reviewing this VSL further as FERC has already allowed ISO/RTO violations investigation to draw in third parties that potentially contributed to the ISO/RTO violation to ensure the appropriate party is fined. The principal is similar here in ensuring the appropriate BA is fined for its violation not the violations/failures of other BAs. The background document mentions on page 31 that the motivation for structuring the VSL in this manner was to prevent BAs in multiple BA interconnections from being sanctioned disproportionately. We appreciate the draftingteam considering this issue but believe there is a simpler solution. Four VSLs could simply be written based on the percentage the BA misses its own Frequency Response Obligation. Furthermore, the compliance enforcement process already considers if the violation impacted reliability when assessing a sanction

Organization	Question 9 Comment
	.(6) The Frequency Response Obligation (FRO) term is used inconsistently with the definition in the VSLs for R1. The first part of each BA implies that the Interconnection has an FRO. However, the definition specifically states that FRO is the BA's "share of the required Frequency Response". It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection. (7) The implementation plan still references Requirement R5. There is no such requirement .(8) Requirement R1 is not consistent with the recent direction NERC has taken to refocus on reliability and looking forward during compliance audits rather than backwards. For instance, NERC has proposed monitoring internal controls of registered entities because this will provide a reasonable assurance that the registered entity is prepared to comply in the future. Current compliance audits focus mostly on past performance and provide no indication of future reliability. How does Requirement R1 support this forward looking vision when it is a lagging indicator that looks at historical performance? (9) Requirement R4 appears to be inconsistent with Requirement R1 and Attachment A. On page 3, Attachment A states the BA shall set its Frequency Bias Setting to 100% to 125% of it Frequency Response Measure or Interconnection Minimum. However, Requirement R4 states that the BA providing Overlap Regulation Service shall set its Frequency Bias Setting to the sum of its Frequency Bias Settings on FRS Form 1 and FRS Form 2 of its own BA and the BA to which its provides Overlap Regulation Service. For simplicity let's call the BA providing Overlap Regulation Service BA X and the BA receiving the service BA Y. Why would the BA X not set its Frequency Bias Setting to 100% to 125% of the sum of BA X's and BA Y's Frequency Response Measure? This would make Requirement R4 parallel with R2. (10) We do not understand the difference between the two bullets in Requirement R4. They appear to say essentially the same thing and the background document provides no discussion to distinguish their differences. Please provide further explanation.

Response: Thank you for your comments.

(1) The proposed variance alternative could create unnecessary work for different organizations.
(2) The proposed elimination of words could help but, the elimination could bring more questions than benefits.

Organization	Question 9 Comment
(3) The drafting team believes that the language proposed in the draft standard is typical of other standards and is not in violation of anything. (4) The drafting team is coordinating as you stated. (5) VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation. (6) The drafting team has clarified the VSL. (7) The drafting team has corrected the Implementation Plan. (8) The drafting team disagrees. The drafting team believes that this is a performance based standard similar to BAL-001 CPS and BAL-002 DCS requirements. With regards to "internal controls" the drafting team believes that this is an enforcement activity not a standards activity. (9) The drafting team disagrees with your comment. Under the two options in R4 the BAs must still comply with the minimum setting requirements through the calculations performed under R2. In your example, if both BAs turned in FRS Form 1 showing a FBS based on the 100% - 125% minimum these two numbers would be added together for compliance with R4. (10) Under the first bullet, two BAs have submitted two FRS Form 1 document in accordance with R1. Under the second bullet, one entity has turned in a single FRS Form 1 with all information for the two BAs combined.	
Keen Resources Asia Ltd.	A probabilistic/statistical basis needs to be developed for the FRM that assesses for usage of frequency response (causation of frequency error) and not just for provision of it. This would also overcome NERC's singular focus on reaction, and NERC's color-blindness to proaction, pointed out in my reply to question 7.
Response: Thank you for your comment. As part of the ongoing evaluation of Frequency Response this may be considered.	
SPP Standards REview Group	Additional typos:Change the ')' to a '(' in the 4th line of M1 of the standard.No further comment

Organization	Question 9 Comment
Response: Thank you for your comment. This has been corrected.	
Arizona Public Service Company	As mentioned in Item 8 above, the VRF language is too complicated and hard to follow. Even though the VRF poll is non binding, it needs to be clear and simple enough to be understood.
Response: Thank you for your comments. The drafting team is assuming you mean the VSL. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation.	
BC Hydro	BC Hydro respectfully submits these additional comments/observations: 1.The proposed standard seems to indicate that it is applicable to the identified responsible entities at all times. There might be circumstances where a BA that belongs to a multiple-BA Interconnection became isolated and has to operate in restorative mode which might require adjusting the frequency bias to a value less negative than the minimum FBS setting value in order to follow the much reduced load/generation level in the area. We suggest adding some language in either the Applicability section or in individual Requirements to recognize these circumstances. 2.Effective Dates: the proposed standard specifies a fixed period (12-month or 24-month) following Regulatory Approval which may fall in the middle of the year while the calculation and implementation are performed on an annual basis. Does this represent any conflicts? 3.The proposed standard does not clearly specify whether a BA must chose between using fixed bias or variable bias for the entire year. Should BAs be allowed to switched back and forth between the two methods? If yes, more details may be needed to account for the FRM and minimum FBS. 4.The proposed standard does not clearly specify whether a BA can be part of a FRSG for only part

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<tr><td></td><td>of the year or must be the whole year

5.The definition of FRO, FRM, FBS, etc. should all include language to indicate the “negative” nature of the value.

6.Measure M2 should have “and uses a fixed bias” added for clarity purpose.

7.In the Additional Compliance Information section of the proposed standard the following info still exists: For Interconnections that are also Balancing Authorities, Tie Line Bias control and fFlat Ffrequency control are equivalent and either is acceptable. Since all reference to AGC Modes have been removed from the Requirements, this additional info should also be removed.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments.

(1) The drafting team does not believe that there is any difference between adherence to the current standard and the proposed standard. With regard to islanded operations, the drafting team believes that other standards prevail under those conditions.
(2) The timelines are not requirements and may be adjusted to meet the annual calculation process proposed by the standard.
(3) The drafting team believes the standard as drafted, allows for two types of bias, fixed and variable. A fixed bias is a single number for the entire period. A number that changes within the period is a variable bias and is subject to Requirement R3.
(4) FRS Form 1 and 2 allows for the transfer of Frequency Response on a per event basis.
(5) While the desired value of the FRM would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1. The FBS definition states that it is an inverse contribution to the interconnection frequency; therefore the definition does not need to reference a negative value. The FRO will be an allocation of the IFRO whose calculation methodology will provide a negative number. The allocation of a negative number will result in a negative number. For these reasons the SDT did not modify the definitions.
(6) Requirement R2 is only applicable to entity’s using a fixed bias therefore Measure M2 only applies to those utilizing a fixed bias.
(7) The proposed elimination of words could help but, the elimination could bring up more questions than benefits.</td></tr>
<tr><td>Edison Electric Institute</td><td>EEI supports the efforts and improvements made by the Standards Drafting Team (SDT) in the latest version of BAL-003 and believe those changes have been responsive to the directives in Order 693. However, we recognizes that the Industry has struggled with this standard and remains split as to how best to respond to those directives and in some cases there are those who question</td></tr>
</table>

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	whether a standard is even necessary. Given the many open issues and the concerns expressed by stakeholders we anticipate that this standard will once again fail to achieve sufficient support to gain approval. Should the Standard fail to achieve ballet approval, it is our hope that NERC Staff and the NERC Board of Trustees will allow the SDT a little more time to resolve any final issues that have been identified in this latest ballet. Although we recognize that May 31, 2013 does not leave the ERO with a lot of time to comply with this FERC imposed deadline, we still remain confident that given the progress made by the SDT a standard, which is acceptable to the Industry, is still possible. To the extent EEI can help, we are committed to working with member companies to communicate the issues and exchange insights from the SDT to help as we can to achieve a positive outcome.
Response: Thank you for your comment and support.	
Manitoba Hydro	Purpose: Is the reference to 'Interconnection Frequency' supposed to be 'Frequency Response'? This would be consistent with later wording in the standard. R1: (1) The acronym 'FRO' is used inconsistently within the document. (2) The phrase "to ensure that sufficient Frequency Response ..." should be separated from the requirement as it is (i) not descriptive of the required actions (ii) redundant with the stated purpose at the beginning of the standard. In general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met. M1: The reference to 'documented formula' is not clear. Does this imply that the FRSG or BA have a record of their calculation? In addition, there is a typo, a random ')' after FRM. M2: Should include the words 'and uses a fixed Frequency Bias Setting...' after overlap Regulation

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	Service to make the wording consistent within the Requirement. M3: The wording of this measure switches tenses between 'is' and 'was'. For consistency, we suggest that this be corrected. NERC Glossary definition of an FRSG is a group of BAs that collectively maintain, allocate and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an FRSG if the RSG Agreement allows for such delegation. Data Retention 1.3. (1) As the standard is currently drafted, both the BA and the FRSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records .(2) In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an FRSG - the BA or the FRSG or both.

Response: Thank you for your comments. The drafting team believes that the purpose statement is correct as written. The standard is for both Frequency Response and Frequency Bias Setting both of which support Interconnection Frequency.

(1) The drafting team corrected the identified FRO inconsistencies within the documents.
(2) The drafting team was advised by NERC staff to include the language you are referencing.
(3) M1 – Yes the entity must have a record of their calculation. The typo has been fixed.
M2 - Requirement R2 is only applicable to entity's using a fixed bias therefore Measure M2 only applies to those utilizing a fixed bias.
M3 – The drafting team corrected the use of "is" in the last line of the measure.
(4) The drafting team believes that any agreement between members of a RSG is an issue that the RSG would handle. We have a created the FRSG to address the concerns that an existing RSG may or may not be a FRSG.

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Data Retention **(1) Both the BA and FRSG must maintain data. At a minimum the BA needs data to document its bias setting obligation. In addition, the BAs data may be needed to demonstrate FRSG performance.** **(2) The drafting team believes that the language is clear; the entity that is found non-compliant would be the entity that would be required to keep the data.**	
JEA	R1 places the burden for compliance on the BA but the BA does not control generation assets and should not be solely responsible for maintaining frequency response. While the standard can still define the amount of Frequency Response for each BA, there needs to be an obligation on the GO/GOP to provide that service as directed by the BA and they should also be held accountable for compliance. Finally, we do not believe that a sufficient study has been conducted to determine the impact of this standard. We are concerned that a substantial number of compliance issues could result and that the resulting cost to maintain compliance could be excessive and we suggest it be put through the Cost Effective Analysis Process (CEAP). We suggest that the proposed values be evaluated on a sample size within each region to determine the number of compliance issues and for those issues that are found determine what the BA would have to do be compliant.
Response: **Thank you for your comments. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).** **There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.** **To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?**	

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MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place. Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.). The SDT does not believe that there is a need to perform a "cost analysis". The numbers are lower than the numbers we are presently seeing.	
Los Angeles Department of Water and Power	Spinning reserves are intended to support the interconnection response to the loss of a resource. If BAL-003-1 is adopted through this Project, the LADWP recommends that the spinning reserve requirements of BAL-002-0.1b and BAL-STD-002-0 be removed, as the Spinning reserve requirement would require utilities to reserve resources in excess of the reserves required in BAL-003-1. LADWP recognizes that this recommendation may be handled through a separate NERC Project, but wanted to submit this comment to bring light to this potential conflict in Reliability Standards.
Response: Thank you for the observation.	
Tacoma Power	The addition to the Frequency Bias Setting definition of "and discourage response withdrawal through secondary control systems" seems incomplete. Tacoma Power does not see anything in the standard that addresses (or measures) how a frequency bias setting will discourage response withdrawal through secondary systems. This should either be more fully addressed or removed.

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Response: The FRI Report and the Background Documents contain explanations on this issue.	
SERC OC Standards Review Group	The comments expressed herein represent a consensus of the views of the above namedmembers of the SERC OC Standards Review Group only and should not be construed as theposition of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for the clarification	
Duke Energy	The concern raised in Duke Energy's comments in item 4 will not be a factor for a few years, but will be an issue as more and more BAs are in the position of their FRM being better than the Interconnection Minimum allocation. We believe that the language that we proposed for calculating the minimum FBS in a multiple-BA Interconnection allows for the proper incentives for BAs to maintain FRM much better than required, and allows for comparable measurement of secondary control performance between similarly-sized BAs, while presenting no risk to reliability.
Response: Thank you for your comment. The industry will utilize information from the process related to this standard to make future decisions. Also, please refer to our response to your Question #4 comment.	
Puget Sound Energy	The definition of "Frequency Response Obligation" applies only to a Balancing Authority. However, requirement R1 applies to both FRSGs and BAs and includes a Frequency Response Obligation that applies to each of those entities. As a result, the definition must also address an FRSG's Frequency Response Obligation. The acronym for Balancing Authority is not included following the first reference to the term in requirement R1 (looks like an inadvertent deletion). Requirement R1 states that an entity "... shall achieve an annual Frequency Response Measure (FRM)...." However, the definition of Frequency Response Measure already includes the concept of annual. As a result, the word "annual" should be removed from the requirement. Requirement R1 includes the language "... to ensure that sufficient Frequency Response is provided

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	by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." This language is a purpose statement rather than a requirement applicable to a FRSG or a BA and should be excluded from the requirement. So long as an FRSG or BA achieves the FRM calculated in accordance with Attachment A, it has done everything necessary to comply with the standard. There are discrepancies between the implementation plan and the proposed standard:- The definitions of "Frequency Response Measure" and "Frequency Response Obligation" in the Implementation Plan are different from those proposed in the draft standard.- The Implementation Plan references "Reserve Sharing Group" rather than "Frequency Response Sharing Group".- The Implementation Plan does not include a definition for the term "Frequency Response Sharing Group".- The Implementation Plan continues to reference R5 in the discussion of the standard's proposed effective date. The annual process dates listed on page 32 of the Background document appear to be inconsistent with those listed in Attachment A.
Responses: Thank you for your comments. **The calculation of FRO is done at the individual BA level. Those BAs that are part of a FRSG must sum their individual FROs to determine the FRSG FRO. This is clearly stated in Attachment A.** **The drafting team corrected this oversight.** **The drafting team disagrees that the term "annual" should be removed as it provides greater clarity as written.** **The drafting team was advised by NERC staff to include the language you are referencing.** **The drafting team has corrected the Implementation Plan.** **The dates are not firm dates but are examples for the process.**	
California Independent System Operator	The ISO supports the development of BAL-003-1 and would like to offer the following comments/suggestions: (1) Some BAs may have to develop a new Ancillary Service product to ensure that its FRO can be met and believes that 12 months after FERC's approval may not provide adequate time to

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	stakeholder and modify market software applications. The ISO suggest increasing the implementation timeline by at least one more year. (2) If the implementation timeline cannot be changed, then the ISO suggests that compliance should be waived for the first year of operation under BAL-003-1. (3) Some BAs may elect to procure a portion of its FRO through bilateral agreements for certain hours (e.g. off-peak) with a neighboring BA. Since a contingency could be in a BA other than the two BAs under a bilateral agreement, the standard or background document needs to clarify the duration of frequency response so that transmission reservation is not a requirement for frequency response. The ISO believes that the BA experiencing the contingency should have adequate arrangements in place to deal with internal contingencies.
Response: Thank you for your comments. **(1) The implementation date for Requirement R1 is 24 months after FERC approval, not 12 months. We believe that this would provide ample time.** **(2) See (1) above.** **(3) The measurement period is 20 to 52 seconds after the beginning of the event. Additionally, there is no mention of transmission requirements for purchase or delivery of Frequency Response.**	
Portland General Electric Company	The issue with proposed Reliability Standard BAL-003-1, requirement R1, is that the Annual Frequency Response Measure (FRM) is determined after the fact with an entity unable to identify or monitor compliance (on non-compliance) along the way. Also, the requirement seems to go the opposite direction of NERC's risk based initiatives where collecting historic compliance information become unsustainable.
Response: Thank you for your comments. **(1) The identification and posting of events will occur on a quarterly basis as stated in the Procedure Document. This will allow BAs to monitor their compliance.** **(2) The SDT believes that this is a performance based standard similar to BAL-001 CPS and BAL-002 DCS requirements.**	

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MRO NSRF	The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R2. To ensure a consistent approach in the application of BAL-003-1, recommend R2 be revised as follows: R2). Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation ...
Response: Based on the comment rather than the proposed language the drafting team is providing the following response. The drafting team discussed the applicability of bias requirements to single BA Interconnections extensively. The consensus of the FRSDT was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.	
Southern Company	The organization selecting events must ensure that the change in frequency is outside the normal dead-band of generator governors. Many of the events selected in the past have not been outside the dead-band and therefore, the frequency response was much less than expected. Southern Company proposes .07 which is consistant with WECC.
Response: Thank you for your comments. The drafting team has created a Procedure Document that details the event selection criteria for each Interconnection. This should alleviate the concern of smaller events being selected.	
Independent Electricity System Operator	The proposed effective date for this standard conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of Section A1.3 and A1.4, after "months after applicable regulatory approval", of the standard to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."The same change should be made to the two bullets in the proposed Implementation Plan.
Response: The drafting team appreciates your comment. However, this language is required to be used by the drafting team with	

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the only modification allowed to be the number of months prior to implementation.	
Northeast Power Coordinating Council	The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.
Response: The FRM is not intended to measure response to AGC signals but is intended to measure response to frequency changes. Therefore, the drafting team does not believe that any modification is warranted.	
Consolidated Edison Co. of NY, Inc.	The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.
Response: The FRM is not intended to measure response to AGC signals but is intended to measure response to frequency changes. Therefore, the SDT does not believe that any modification is warranted.	
Tucson Electric Power	This is an important task and the efforts of the drafting team are appreciated.
Response: Thank you for the recognition.	
The United Illuminating Company	UI believes the VRF should be High. The VRF justification for Medium is that the prior year's bias setting would exist in the control system so the impact would not cause a Cascade. UI thinks that is an adjustment factor that is applied after non-compliance is determined. Not having settings is likely to cause cascade so the VRF is High.
Response: The drafting team reviewed the definition for the VRF levels and believes that the appropriate levels were used for each requirement.	
Tri-State Generation and	We are concerned with the tariff implictations associated with this standard. Will this standard

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Transmission Assn., Inc.	create the need for an additional ancillary service under the FERC pro forma OATT?
Response: The drafting team believes that your comment is possible but does not think that it is in the scope of NERC to make changes to the FERC pro forma OATT.	
NREL Transmission and Grid Integration Group	We commend the drafting team for a rigorous approach to this new and important standard. Being observers who have a strong interest in this standard as it applies to much of the research that we do, but not stakeholders of the ultimate standard, we submit our overall comments as recommendations here. We believe there are a few potential issues, that may at least need more thought before going forward. The first is the credit for LR. (1) Overfrequency can be an issue: using ERCOT as an example, with -282 MW/0.1Hz response and 1400 MW of LR all responsive at 59.7 Hz, if just meeting FRO requirements, the 1400MW LR can all be triggered with a loss of (282*3=) 846MW, causing (1400-846=)554MW of overgeneration. This can be exacerbated by further increases of LR without recognition of the triggering frequency, and the disconnect between BA and interconnection in the other interconnections. (2) With crediting LR toward the Interconnection, it will not give incentive toward BAs to provide it. We believe the LR should contribute to the BA FRO rather than discount the IFRO. (3) There is no requirement for frequency response capacity (ie MW) available to provide the FR. This is a nonissue in today's world with the amount of spinning reserve already available, but the issue could be apparent on future systems with increased reserve sharing, or reserve capacity from resources that operate in modes which do not provide frequency response. The European Interconnection requirement has two intentions: a 3,000 MW capacity requirement and a 1,500 MW/0.1Hz FRO requirement that is allocated out to its Transmission System Operators. This could solve the issue with LR and generators, where LR is in MW and generation governing is in MW/0.1Hz. (4) It is likely, and from our understanding is true in some areas like ERCOT, that the LR is selected based on market solutions, and may not be available all times of the year. This is another reason why the LR should contribute to the BA FRO rather than discount the IFRO. (5) It may be beneficial to guide frequency settings for LR or even multiple settings to mimic a

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	droop curve for LR. Other potential issues not related to the LR. We think the SDT has done an outstanding job on reviewing the data sets and determining statistically based values to better account for different factors that may affect minimum frequency levels. We agree that there are current issues in the primary governing response, but that there may be a disconnect in fixing those issues with the static values. We also agree that there is not an easy solution. In specific: (a) The static CB ratio might not incentivize BAs to improve response with increased inertia or faster responding governing response. (b) The static withdrawal BC'adj may not incentivize BAs to improve their governing response and limit their withdrawal. Improved technology may allow for better measurement to account for these issues dynamically rather than using static numbers. Guidance on increasing inertia, increasing governing speed, and reducing withdrawal should be considered by stakeholders. We thank NERC and the SDT for the opportunity to provide comments on this important standard.
Response: Thank you for your comments. **(1) The standard as presently written addresses both over and under frequency events.** **(2) The credit given for LCR is based on numbers provided by the interconnection. The utilization of load by any individual BA will be included in the calculation of their FRM through the Net Actual Interchange term rather than the IFRO.** **(3) Thank you for your comment.** **(4) Please refer to our response to (2) above.** **(5) Thank you for your comment. As more information is gained through implementation of this standard modifications based on this information will be possible.**	
Ameren	While we support this draft, we believe that this might only be a starting point and as additional knowledge and experience is gained through the implementation of this standard and other efforts such as the FRI, that the improvements can be embraced by all parties, even if those improvements result in relaxed requirements.
Response: Thank you for your comments. The NERC process allows for adjustments and improvements for both its thresholds and	

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methodologies when operational experience has been gained.	
Xcel Energy	Xcel Energy supports this proposed revision to the standard as a first step and suggests that after operating for a couple of years under the revised standard, that NERC initiates a more complete study to support any modifications to the standard.
Response: Thank you for your comment. The drafting team agrees.	

END OF REPORT

Exhibit J

Analysis of how VRFs and VSLs were Determined

Using Commission Guidelines

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-12 – Frequency Response

This document provides the drafting team's justification for assigning draft standard Requirement violation risk factors (VRFs) and violation severity levels (VSLs) for:

- BAL-003-1 — Frequency Response and Frequency Bias Setting

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 violation 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
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.

[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.

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 Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

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 VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in this standard 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 non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance 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 non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties per violation per day basis is the “default” for penalty calculations.

VRF and VSL Justification

BAL-003-1 VRF and VSL Justifications		
R1	Proposed VRF	Medium
	NERC VRF Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support for the contingency. This is consistent with the NERC definition.
	FERC VRF G1 Discussion	This Requirement is more administrative in nature requiring calculated FRM to be equal to or more negative than FRO. The requirement does not directly correlate to the list of critical areas identified in the FERC VRF Guideline 1. Guideline 1 appears to conflict with guideline 4. Guideline 1 identifies a list of topics that encompass nearly all topics within the NERC 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 on the reliability of the system. The SDT believes that Guideline 4 better reflects the intent for assigning VRFs for this standard since this approach is focused on the reliability impact of the requirement.
	FERC VRF G2 Discussion	Consistency within a Reliability Standard exists. This Requirement does not contain Parts. Requirement action is unique with respect to other standard requirements. All standard requirements have a common reliability focus relevant to Frequency Response and Frequency Bias Setting.
	FERC VRF G3 Discussion	The Requirement VRF is consistent with other BES standards addressing responsiveness. This requirement is similar in concept to the current enforceable BAL-003-0.1b standard Requirement R2 which specifies a Medium VRF.
	FERC VRF G4 Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support for the contingency. This is consistent with the NERC definition.
	FERC VRF G5	This requirement does not co-mingle reliability objectives.

	Discussion	
	Proposed Lower VSL	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's FRO and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO
	Proposed Moderate VSL	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's FRO and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
	Proposed High VSL	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its FRO and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO
	Proposed Severe VSL	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its FRO and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
	Compliance with NERC Revised VSL Guidelines	The NERC VSL guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated FRM being less negative than FRO.
	FERC VSL G1 Discussion	This is not applicable since there was not a Requirement mandating a certain level of Frequency Response prior to this standard.
	FERC VSL G2 Discussion	Proposed VSL's is 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 the calculated FRM is less negative than FRO.
	FERC VSL G3 Discussion	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.
	FERC VSL G4 Discussion	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

R2	Proposed VRF	Medium
	NERC VRF Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support f the contingency. This is consistent with the NERC definition.
	FERC VRF G1 Discussion	This Requirement is more administrative in nature requiring entities to implement the Frequency Bias Setting validated by the ERO. The requirement does not directly correlate to the list of critical areas identified in the FERC VRF Guideline 1. Guideline 1 appears to conflict with guideline 4. Guideline 1 identifies a list of topics that encompass nearly all topics within the NERC 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 on the reliability of the system. The SDT believes that Guideline 4 better reflects the intent for assigning VRFs for this standard since this approach is focused on the reliability impact of the requirement.
	FERC VRF G2 Discussion	Consistency within a Reliability Standard exists. This Requirement does not contain Parts. Requirement action is unique with respect to other standard requirements. All standard requirements have a common reliability focus relevant to Frequency Response and Frequency Bias Setting.
	FERC VRF G3 Discussion	The Requirement VRF is consistent with other BES standards addressing responsiveness. This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R1 which specifies a Lower VRF however BAL-003-1 Requirements R1, R3, and R4 specify a Medium VRF and the SDT believes it is appropriate for this Requirement to also possess a Medium VRF given the nature of the revision to BAL-003-0.1b.
	FERC VRF G4 Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support f the contingency. This is consistent with the NERC definition.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.

	Proposed Lower VSL	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.
	Proposed Moderate VSL	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.
	Proposed High VSL	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.
	Proposed Severe VSL	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
	Compliance with NERC Revised VSL Guidelines	The NERC VSL guidelines are satisfied by incorporating increments for tardiness implementing the validated Frequency Bias Setting into the ACE calculation.
	FERC VSL G1 Discussion	This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R1 which specifies a Lower VRF. Proposed VSL's meet or exceed the current threshold of compliance.
	FERC VSL G2 Discussion	Proposed VSL's is not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on how late the validated Frequency Bias Setting is implemented.
	FERC VSL G3 Discussion	Proposed VSL's do not expand on what is required. The VSL's assigned only consider performance of required action. Proposed VSL's are consistent with the requirement.
	FERC VSL G4	Proposed VSL's are based on a single violation and not a cumulative

	Discussion	violation methodology.

R3	Proposed VRF	Medium
	NERC VRF Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting in its ACE equation and would provide support for a contingency. This is consistent with the NERC definition.
	FERC VRF G1 Discussion	This Requirement is more administrative in nature requiring entities to implement a Frequency Bias Setting validated by the ERO. The requirement does not directly correlate to the list of critical areas identified in the FERC VRF Guideline 1. Guideline 1 appears to conflict with guideline 4. Guideline 1 identifies a list of topics that encompass nearly all topics within the NERC 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 on the reliability of the system. The SDT believes that Guideline 4 better reflects the intent for assigning VRFs for this standard since this approach is focused on the reliability impact of the requirement.
	FERC VRF G2 Discussion	Consistency within a Reliability Standard exists. This Requirement does not contain Parts. Requirement action is unique with respect to other standard requirements. All standard requirements have a common reliability focus relevant to Frequency Response and Frequency Bias Setting.
	FERC VRF G3 Discussion	The Requirement VRF is consistent with other BES standards addressing responsiveness. This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R1 which specifies a Lower VRF however BAL-003-1 Requirements R1, R2, and R4 specify a Medium VRF and the SDT believes it is appropriate for this Requirement to also possess a Medium VRF given the nature of the revision to BAL-003-0.1b.
	FERC VRF G4 Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support for a contingency. This is consistent with the NERC definition.
	FERC VRF G5	This requirement does not co-mingle reliability objectives.

	Discussion	
	Proposed Lower VSL	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.
	Proposed Moderate VSL	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.
	Proposed High VSL	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.
	Proposed Severe VSL	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
	Compliance with NERC Revised VSL Guidelines	The NERC VSL guidelines are satisfied by incorporating percentage of noncompliance performance for the calculated average Frequency Bias Setting being less negative than its minimum as defined in Attachment B.
	FERC VSL G1 Discussion	This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R1 which specifies a Medium VRF. Proposed VSL's meet or exceed the current threshold of compliance.
	FERC VSL G2 Discussion	Proposed VSL is not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based on the calculated average Frequency Bias Setting being less negative than its minimum as defined in Attachment B.

	FERC VSL G3 Discussion	Proposed VSL does not expand on what is required. The VSLs assigned only consider compliance with the Frequency Bias Setting calculation and implementation required. Proposed VSL's are consistent with the requirement.
	FERC VSL G4 Discussion	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

R4	Proposed VRF	Medium
	NERC VRF Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the previous year's Frequency Bias Setting already in its ACE equation and would provide support f the contingency. This is consistent with the NERC definition. In addition, this Requirement VRF is consistent with the BAL-003-0 Requirement which has been approved by FERC.
	FERC VRF G1 Discussion	This Requirement is more administrative in nature requiring entities providing Overlap Regulation Services to correctly increase its Frequency Bias Setting. The requirement does not directly correlate to the list of critical areas identified in the FERC VRF Guideline 1. Guideline 1 appears to conflict with guideline 4. Guideline 1 identifies a list of topics that encompass nearly all topics within the NERC 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 on the reliability of the system. The SDT believes that Guideline 4 better reflects the intent for assigning VRFs for this standard since this approach is focused on the reliability impact of the requirement.
	FERC VRF G2 Discussion	Consistency within a Reliability Standard exists. This Requirement does not contain Parts. Requirement action is unique with respect to other standard requirements. All standard requirements have a common reliability focus relevant to Frequency Response and Frequency Bias Setting.
	FERC VRF G3 Discussion	The Requirement VRF is consistent with other BES standards addressing responsiveness. This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R6 which specifies a Medium VRF
	FERC VRF G4 Discussion	This Requirement, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system but would unlikely result in the bulk electric system instability, separation, or cascading failures since a Balancing Authority would have the

		previous year's Frequency Bias Setting already in its ACE equation and would provide support f the contingency. This is consistent with the NERC definition. In addition, this Requirement VRF is consistent with the BAL-003-0 Requirement which has been approved by FERC.
	FERC VRF G5 Discussion	This requirement does not co-mingle reliability objectives.
	Proposed Lower VSL	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting error less than 10% of the validated or calculated value.
	Proposed Moderate VSL	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting error more than 10% but less than or equal to 20% of the validated or calculated value
	Proposed High VSL	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting error more than 20% but less than or equal to 30% of the validated or calculated value.
	Proposed Severe VSL	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with setting error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services
	Compliance with NERC Revised VSL Guidelines	The NERC VSL guidelines are satisfied by incorporating percentage of noncompliance performance for the absolute value of the Balancing Authorities' calculated monthly average Frequency Bias Setting being below the minimum percentage specified by the ERO. The VSL also includes a binary requirement for failing to change the Frequency Bias Setting value when providing Overlap Regulation Services.
	FERC VSL G1 Discussion	This Requirement is similar in concept to the current enforceable BAL-003-0.1b Requirement R6 which specifies a Medium VRF. Proposed VSL's meet or exceed the current threshold of compliance.
	FERC VSL G2 Discussion	Proposed VSL's has both a percentage of noncompliance performance and binary element. The binary element is designated severe. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated monthly average Frequency Bias Setting is below the minimum percentage specified

		by the ERO or if the entity fails to change the Frequency Bias Setting value when providing Overlap Regulation Services.
	FERC VSL G3 Discussion	Proposed VSL’s do not expand on what is required. The VSL’s assigned only consider results of the calculation required and if the Frequency Bias Setting is correctly set when providing Overlap Regulation Services. Proposed VSL’s are consistent with the requirement.
	FERC VSL G4 Discussion	Proposed VSL’s are based on a single violation and not a cumulative violation methodology.

Project 2007-12 Frequency Response

Name and Title	Company	Contact Info	Bio
David Lemmons – Chair Senior Manager, Market Operations	Xcel Energy, Inc	303.571.6520 david.f.lemmons@xcelenergy.com	David Lemmons began his career in the electric industry with Southwestern Public Service Company (SPS) in Amarillo, Texas in 1989. He spent 8 years in the Rates and Regulation Department where he performed rate of return analyses, designed rates and worked with other regulatory issues. In 1997, David moved to the Energy Trading Department during the merger between SPS and Public Service Company of Colorado (PSCo). In this capacity, with Xcel Energy and its predecessor, New Century Energies, he analyzed the electric system loads and resources for day-ahead and real-time operations and trading, working with generation and fuel procurement to ensure resources were ready and available to serve loads. Since 2001, in the positions of Manager and Senior Manager of Market Operations, he has represented Xcel Energy at electric reliability, RTO development and system operation meetings throughout the United States as well as providing support for state and Federal regulatory proceedings. He has a Master of Science in Finance and Economics from West Texas A&M University.
Terry Bilke – Vice-chair Consulting Advisor	Midwest Independent System Operator	317-249-5463 TBilke@misoenergy.org	Terry Bilke is a Consulting Advisor in the Compliance Services department at MISO. He has over thirty years of power system operations and maintenance experience, 16 years of this as a transmission and balancing authority operator. He is a former chair of the NERC Resources Subcommittee and is presently chair of the NERC Compliance and Certification Committee. Terry received his PhD in Quality Systems from Indiana State University, MSME from Colorado State University, and MBA from the University of Wisconsin-Whitewater.

Don Badley	Northwest Power Pool	503-445-1076 don.badley@nwpp.org	Don Badley has been a member of the Northwest Power Pool (NWPP) Staff since 1975. Don manages the NWPP Operating Committee. He is currently Chairman of the North American Electric Reliability Corporation (NERC) Resources Subcommittee, a member of Western Electricity Coordinating Council's (WECC) Performance Work Group and has chaired numerous NERC and WECC groups. In the past Don has served as Chairman of the North American Power Systems Interconnection Committee's Performance Subcommittee, a member of the WECC Technical Operations Subcommittee, and a member of the WECC Control Work Group. Regarding his association the Institute of Electrical and Electronics Engineers (IEEE), Don is a member of the IEEE Power Engineering Society and has co-authored three IEEE papers on system control. Don has served as Chairman of the Oregon Section and Area Chairman for the States of Alaska, Oregon, and Washington.

Howard Illian President	Energy Mark, Inc.	847-913-5491 howard.illian@energymark.com	Howard F. Illian graduated from Carnegie Institute of Technology (Carnegie-Mellon University) in 1970 with a B.S. in Electrical Engineering. From 1970 until 1982 he worked for ComEd in the field of Operations Research, and was Supervisor, Economic Research and Load Forecasting from 1976 until he was reassigned to Bulk Power Operations in 1982 where he was Technical Services Director when he retired in 1998. He is now President of Energy Mark, Inc., a consulting firm specializing in the commercial relationships required by restructuring. He has authored numerous papers, and has testified as an expert witness before the Illinois EPA, the Federal EPA, the Illinois Commerce Commission and the Public Utility Commission of Texas. He has developed and applied several new mathematical techniques for use in simulation and decision making. He has served on the NERC Performance Subcommittee, the Interconnected Operations Services Implementation Task Force, the Joint Inadvertent Interchange Task Force, and the NAESB Inadvertent Interchange Payback Task Force. Recent work includes significant contributions to the development of new NERC Control Performance Standards including the Balancing Authority Ace Limit and a suggested mathematical foundation for control based on classical statistics. His current research concentrates on the development of technical definitions for Ancillary or Reliability Services including frequency response and their market implementation.

Clyde Loutan Senior Advisor	California ISO	916-608-5917 cloutan@caiso .com	Clyde Loutan is presently a Senior Advisor at the California Independent System Operator Corporation (ISO) focusing on power system operation performance, and is the lead investigator for the ISO's renewable resource integration technical studies. He is a technical subject matter expert on power grid planning, system operations, and renewable energy integration. Mr. Loutan previously worked at the Pacific Gas and Electric Company for 14 years in various capacities such as Real Time System Operations, Transmission Planning and High Voltage Protection. Mr. Loutan is a licensed professional engineer in the State of California. He holds B.S. and M.S. degrees in Electrical Engineering from Howard University in Washington D.C., and is a senior member of the IEEE.

Carlos Martinez	CERTS	cmartinez@asresearchers.com	Carlos Martinez is presently leading for the Consortium for Electric Reliability Technology Solutions (CERTS) and Advanced Systems Researchers, Inc., (ASR) a group of researchers and analysts investigating, deploying and field testing advanced real time reliability monitoring applications for identifying interconnections load-generation and grid controls adequacy, reliability performance, and trends. He participates in North American Electric Reliability Corporation (NERC) Standard Drafting Teams researching, recommending and field testing load-generation and grid control performance standards. Carlos holds a MS in Electrical Engineering from the University of Miami, Florida, and brings 30 years of experience in the electricity power industry first deploying and supporting advanced monitoring applications at Florida Power and light, second as Manager of Southern California Edison Energy Management System (EMS) and 4 SCADA systems, and during the last 10 years working on advanced, applied research for processes optimization, risk analysis, control, monitoring and geo-graphic visualizations for Lawrence Berkeley National Laboratory (LBNL), Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC). After the Eastern blackout of August 14, 2003 Carlos chaired the NERC Frequency-ACE Investigation Team (FAIT).

Sydney Niemeyer Control System Specialist	NRG Texas LP	713-795-6108 sydney.niemeyer@nrgenergy.com	Sydney L. Niemeyer started with Houston Lighting and Power Co. in June of 1969 as a Cooperative Education student. He earned a B.S. in Electrical Technology in 1975 from the University of Houston. Between 1972 and 1988 he worked as an Instrument control technician, Master Instrument & Control Technician and Crew Leader at various plants including the startup of 7 of the 59 units at 11 sites. In 1988 he coordinated the installation and placed in service RTU's at each site and interfaced new AGC for each unit. He developed and implemented a computer program to monitor the startup processes of large steam turbines. In 1997 he transferred to the generation dispatch division and managed the AGC of all units for what is now NRG Texas. Since then he has been involved with numerous ERCOT and NERC task forces, working groups and committees including: Performance, Disturbance and Compliance Working Group (PDCWG) of ERCOT; Resources Subcommittee of NERC and its Frequency Control and Reserves Working Groups; NERC Eastern Interconnection August 4, 2007 frequency event investigation team; NERC Frequency Response Standard Drafting Team and the ERCOT BAL-001-TRE-1 Regional Standard Drafting Team.
Mike Potishnak Principal Engineer	ISO New England, Inc.	413-535-4308 mpotishnak@iso-ne.com	Mike Potishnak is a Principal Engineer for ISO New England since 1989. He has been a member of the NERC Resources Subcommittee for the past 15 years, and has participated in the Balancing Authority Reliability-based Control Standard Drafting Team in addition to the Frequency Response Standard Drafting Team. He has been the engineer with primary responsibility for Automatic Generation Control for more than 20 years, and has played a major role in ISO New England's regulation markets prior to their inception in 1999. He also has substantial experience in monitoring and enhancing generator governor response.

Tom Washburn Executive Director	Florida Municipal Power Pool	407-434-4228 TWashburn@ouc.com	With over 40 years of experience, Tom Washburn has provided a diverse set of services to Orlando Utilities Commission and the Florida Municipal Power Pool. As Vice President of the Transmission Unit at Orlando Utilities Commission, he was responsible for the planning, regulatory permitting, construction and operation of over 300 miles high voltage transmission lines, over 30 high voltage substations, and the 24-by-7 system operations of the transmission and generation system. As the Chief Information Officer at Orlando Utilities Commission, Washburn was responsible for all of the Information Technology including microcomputer support, computer applications, computer hardware, telecommunication and the fiber optics data communications. In other management roles at Orlando Utilities Commission, he was responsible for financial planning, load forecasting, rate design, wholesale marketing, and generation planning. Tom Washburn helped form the Florida Municipal Power Pool, which started operation in July 1988. As the first Executive Director of the Florida Municipal Power Pool, since May. 2006, Washburn is responsible for the reliable, economic operation of more than 4,500 megawatts of generation serving 20 municipal utilities in Florida, compliance with the North America Reliability Corporation Reliability Standards, and overseeing the clearinghouse price process for the Pool.

Sandip Sharma Senior Operations Engineer	ERCOT	512-248-4298 ssharma@ercot.com	Sandip Sharma received his M.S.E.E in Electrical Engineering from the University of Texas at Arlington in 2006 specializing in Power Systems. He joined the Electric Reliability Council of Texas Inc., (ERCOT) after graduation, and has been working since then in the Operations Planning group. While working at ERCOT, he was responsible for monitoring overall Frequency Control and Primary Frequency Response performance of the ERCOT Interconnection. He was the primary subject matter expert in governor response analysis post frequency disturbance and Automatic Generation Control/Load Frequency Control tuning. He has authored several IEEE papers and represented ERCOT at various technical conferences on primary frequency response and integration of intermittent resources. He is also a member of the regional standard drafting team (BAL-TRE-001) for the ERCOT region; working on individual generator governor setting and performance requirements.

Robert Cummings Director, Reliability Initiatives and System Analysis	NERC	404-446-9717 bob.cummings@nerc.net	Mr. Cummings joined NERC in 1996 and has extensive experience in the industry in system planning, operations engineering, and wide area planning. He holds a Bachelor of Science Degree in Power System Engineering from Worcester Polytechnic Institute and is an IEEE Senior Member. His geographically diverse experience includes Central Vermont Public Service Corporation in System Planning (generation and transmission), Public Service Company of New Mexico, and the East Central Reliability Coordination Agreement (ECAR). Mr. Cummings was the "father" of power interchange transaction "tagging" and the Interchange Distribution Calculator, which shows loading contributions on key system transmission interfaces, or "flowgates," for the Eastern Interconnection. The Reliability Initiatives and System Analysis group acts provides a consulting engineering function within NERC, performing deep-dive forensic engineering analysis of major system disturbances and providing subject matter expertise to standards drafting teams and various other areas of NERC staff. Cummings was intimately involved in the investigation team of the 2003 blackout as a team leader and the more recent September 8, 2011 Arizona-Southern California Outage analysis. In both instances he led multiple teams with responsibilities in the sequence of events development, modeling and studies (powerflow and dynamics analysis), and transmission/generation performance areas. From 2005 through 2009, he directed the NERC Event Analysis and Information Exchange program, directing or working on 12 major disturbance analyses. Mr. Cummings was instrumental in the founding of the NERC System Protection and Controls Task Force, now the System Protection and Control Subcommittee, acting as the staff coordinator from 2004 through 2009. Mr. Cummings is the staff coordinator for the NERC System Analysis and Modeling Subcommittee and is the technical advocate

Darrel Richardson Standards Developer	NERC	609-613-1848 Darrel.richardson@nerc.net	Darrel Richardson joined the NERC staff as a Standards Developer. In this role he facilitates and provides guidance to drafting teams in the development of technically excellent and timely reliability standards for the reliable operation and planning of the bulk power system. Darrel began his career with NERC in November 2007. Darrel has extensive experience in the utility industry having spent over 37 years with Illinois Power Company. In his tenure at Illinois Power he held several different positions in the Engineering, Planning and Operations groups. Among the position he has held are Transmission Coordinator, Generation Coordinator, Manager Wholesale Marketing, Manager Wholesale Marketing and Trading, Director Generation Control and Manager Compliance.