NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on the 1st draft of BAL-003-1 – Frequency Response and Frequency Bias Setting — Project 2007-12

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. These standards were 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.

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 609-452-8060 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
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

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
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

	Group/Individual	Commenter	Organization	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

	Group/Individual	Commenter	Organization	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
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

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

Group/Individual	Commenter	Organization	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

Group/Individual	Commenter	Organization	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

Group/Individual	Commenter	Organization	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

Group/Individual	Commenter	Organization	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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				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
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

Group/Individual		Commenter	Organization	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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	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

Group/Individual		Commenter	Organization	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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				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									
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								

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

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

Organization	Yes or No	Question 1 Comment
		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 modified the definition and it now reads “The data from an individual event from a Balancing Authority that is necessary to calculate its Frequency Response on FRS Form 1, expressed in MW/0.1Hz”. FRM The SDT agrees with your concern with the definition of FRO. The SDT has revised the definition to now read “The Balancing Authority’s 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 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: Patterson response FRM – median or mean		
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

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 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: santee		
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: santee		
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 “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?

Organization	Yes or No	Question 1 Comment
		May need to clarify what FRS stands for.
Response: santee		
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: santee FRM An attachment referenced within a standard becomes part of the standard and is therefore enforcdable.		
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 that 25 events do not apply because an attachment is not part of the standard.
Response: mro		
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: mro		

Organization	Yes or No	Question 1 Comment
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: santee FRM NERC FRS Form 1 has been modified to allow for adjustments (not exclusions).		
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 has prepared a suggested modification to the Rules of Procedure to obligate the ERO to perform the tasks identified in the standard.		
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: santee FRM and FRO NERC FRS Form 1 has been modified to allow for adjustments (not exclusions).		
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).

Organization	Yes or No	Question 1 Comment
		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 these definitions will be used in later revisions to the BAL group of standards and therefore is leaving the definitions in the standard to be added to the NERC Glossary of Terms Used in Standards. Santee cooper (sefd frm fro) Based on analysis of data the SDT has determined that ???? is the proper method to be used in defining FRO.		
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

Organization	Yes or No	Question 1 Comment
		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 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: IRC response		
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".

Organization	Yes or No	Question 1 Comment
Response: SEFRD revised		
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. (2, 4, 5) FRM response (3) The SDT has corrected NERC FRS Form 1. **(6) technical justification**		
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 that the specific calculations should be included in the definition. The SDT has included the calculation methodology in the accompanying attachment (Attachment A). The FRM calculation, using NERC FRS Form 1, has been modified to now include adjustments.		

Organization	Yes or No	Question 1 Comment
FRM response		
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: SEFRD response FRS Form 1 modified		
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. 2) FRM is defined by undefined terms "FRS" and "FRS Form 1". 3) FRO – fine 4) FRS - "Frequency Response Survey"
Response: SEFRD response 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

Organization	Yes or No	Question 1 Comment
		arresting frequency deviation (Point C).
Response: The SDT has added a text box in the standard to explain the relationship. The text box states”		
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: The SDT believes that these definitions will be used in later revisions to the BAL group of standards and therefore is leaving the definitions in the standard to be added to the NERC Glossary of Terms Used in Standards.		
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. FRM response		
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. FRM response		
Seattle City Light	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comment
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.		
ISO New Engand Inc.		
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
Xcel Energy		

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:

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 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”.		
ENBALA Power Networks	No	: ENBALA would modify the above as follows: A 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 AGC System to ignore the export or import caused by the Primary Frequency Response.
Response: santee response		

Organization	Yes or No	Question 2 Comment
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: santee response		
EKPC	No	"Frequency Bias" should not be used in the definition."Usually" can be omitted.
Response: santee response		
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 feels your suggested definition could be confusing in that primary Frequency Response cannot be delivered by AGC. Santee response		
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

Organization	Yes or No	Question 2 Comment
		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: santee response		
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. 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: santee response With regards to you suggestion concerning the need for the definition of Frequency Response, the SDT believes that is outside the scope of the industry approved SAR.		
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

Organization	Yes or No	Question 2 Comment
		confused with Frequency Bias Setting and is often used interchangeably with Frequency Response even though the meanings are slightly different.
Response: MISO		
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: santee response		
IRC Standards Review Committee	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: santee response If the ERO provides you with a Frequency Bias Setting then it is considered fixed. If the ERO accepts your 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: IRC		
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".

Organization	Yes or No	Question 2 Comment
Response: santee response		
NIPSCO	No	Frequency Bias and Frequency Response are not the same thing and that may be why "F" & "R" were not 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: santee response		
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: santee response The SDT agrees with your 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: santee response The MW/0.1 Hz is the dimension and is not intended to reference a magnitude. Issues dealing with governor droop are outside of the scope of the industry approved SAR. The SDT agrees with your last comment. That is why the SDT supports variable bias as an alternative.		
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. Santee response		
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: SEFRD response from Q1		
MRO's NERC Standards Review Subcommittee	No	

Organization	Yes or No	Question 2 Comment
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. Santee response		
FirstEnergy	Yes	Although we support the definition, we suggest the word “contribute” be changed to “maintain”.
Response: southern response		
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	
Alberta Electric System Operator	Yes	
Independent Electricity System Operator	Yes	
FMPP	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 2 Comment
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: santee response		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		
ISO New Engand Inc.		
Hydro-Quebec TransEnergie		
Xcel Energy		

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:

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 drafting team appreciates your comment. The drafting team points out that for the field trial, the minimum level of response needed will be set using a deterministic approach. The ultimate level of required response required in a final standard may be set using field trial information. The SDT is using a project schedule that has been approved by FERC for the development of a BAL-003 standard. Any modifications to this schedule would need 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: MRO		
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

Organization	Yes or No	Question 3 Comment
		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: MRO		
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 addressing Frequency Response should clearly be related to unplanned contingencies occurring on the interconnected BES.
Response: The SDT believes that adequate Frequency Response is as important during normal operations as during emergency operations. Measuring Frequency Response is easier to accomplish during contingencies and that is why the SDT has focused in that area.		
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

Organization	Yes or No	Question 3 Comment
		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 FERC directives. The SDT is using a project schedule that has been approved by FERC for the development of a BAL-003 standard. Any modifications to this schedule would need both NERC and FERC approval. The purpose of the standard is to put a backstop in place to prevent unreliable BES operation. Need to address 2nd paragraph		
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

Organization	Yes or No	Question 3 Comment
		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: IRC		
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

Organization	Yes or No	Question 3 Comment
		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: IRC		
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 dictate a specific generation dispatch. The standard is only prescribing a minimum Frequency Response obligation. How a entity meets the obligation is up to the entity.		
NIPSCO	No	Yes, "Interconnection frequency", small "f".
Response: The SDT thanks you for your suggested correction. This has been corrected.		
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 the proposed changes. The drafting team believes that order 693 requires a technological neutral performance standard for the purposes 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.

Organization	Yes or No	Question 3 Comment
Response: the std and focus is to estrablish primary with some sustain ability and that it hands off secondary control in a coordinated manner.		
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: D Lemmons response **FERC approveds** **schedule**		
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: thanks		
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.
Response: thanks		
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.

Organization	Yes or No	Question 3 Comment
Response: thanks **Clarification is located in the Attachment A**		
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	
Westar Energy	Yes	
FMPP	Yes	

Organization	Yes or No	Question 3 Comment
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.		
Hydro-Quebec TransEnergie		
Xcel Energy		

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:

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 agree that the measure is a lagging indicator **Possible change req to report quarterly**		
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 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: we agree that the measure is a lagging indicator – the sdt intends to provide a example **Possible change req to report quarterl**		
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

Organization	Yes or No	Question 4 Comment
		would translate to FRO frequency bias settings and how it will affect the L10 values.
Response: lge		
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: lge		
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: Q3 response **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: mro q3 response		
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,

Organization	Yes or No	Question 4 Comment
		and the plan outline in NERC's October 25, 2010 compliance filing.
Response: mro q3 response		
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 is for each BA to "achieve" its obligation Attachment A is a part of the standard according to NERC rules Variable bias needs further review		
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

Organization	Yes or No	Question 4 Comment
		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: the sdt intends for this to apply to all interconnections - definition modified The standard does not dictate gen dispatch – the standard is only prescribing a min obligation – how a entity meets the obligation is up to the entity FRS Form has been revised		
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 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: IRC		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>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.

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.</td></tr>
<tr><td colspan="3">Response: The standard does not dictate gen dispatch – the standard is only prescribing a min obligation – how a entity meets the obligation is up to the entity

Thanks and corrected - change

PH – deterministic versus probabilistic??

The SDT has modified the FRS Form 1</td></tr>
<tr><td>Southern Company</td><td>No</td><td>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).</td></tr>
<tr><td colspan="3">Response: FRS Form 1 revised

the sdt believes that req 1 calculation methodology used for compliance needs to reference Attachment A and FRS Form 1 in order to be consistent across all interconnections.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
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: PH – load response??? Our methodology attempts to prohibit activation of UFLS on an interconnecdtion basis which further prohibits activiation of PRC-024. Voltage deviations are OOS		
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: possible to include – need to come back to		
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: we agree no compliance measurement on individual events – measure is on a series evaluation on an annual basis		
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

Organization	Yes or No	Question 4 Comment
		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 not included in the operating plan.
Response: 11 - need to assure ourselves that we have identified the weakness in the metric – come back to **12 –** come back to		
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: use ercot response – also apply for variance smaller interconnection should ask for a variance – size of interconnection may matter		
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: sdt considering alt methods – come back to		
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

Organization	Yes or No	Question 4 Comment
		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.
Response: westar		
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: measurement in FRS Form 1 **Couild use criteria for selecting events to check (no guarantee)** – notify on a shorter basis (come back to)		
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: entity determines method for compliance – sar could be submitted		
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: definition changed & FRS Form 1 modified		
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

Organization	Yes or No	Question 4 Comment
		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 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: FRS form 1 modified to allow fopr adjustments **Industry will agree (by ballot on standard)** **Documentation improved** **Mid-year change – come back to**		
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

Organization	Yes or No	Question 4 Comment
		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 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: frs from 1 modified **Attachment A – need to modify to only include what is necessary for 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: come back to		
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 modified & fixed		
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: come back with admininstrative procdedure for ERO FRO		

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: Alberta response		
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: thanks		
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.		
FirstEnergy		
Xcel Energy		

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:

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).
Response: put into requirement or clarity in attach a Administrative procedure – come baqck to		
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: santee cooper		
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).

Organization	Yes or No	Question 5 Comment
Response: santee cooper		
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: santee cooper **Come back to date**		
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: modified attachment a and administrative procedure Margin and flexibility – come back to		
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

Organization	Yes or No	Question 5 Comment
		always over-biased. The standard needs to allow some margin in the frequency bias setting to ensure that the bias setting is overbiased.
Response: MRO		
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: MRO		
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: wqill provide example in attachment a **ROP will be modified**		
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: ero to validate and provide a coordinated distribution of FBS Attachment A modified Attachment A modified Variable bias – come back to		
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: Attachment A modified – come back to **Put "to ensure effective...**control" in dialog box		
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: clarify – come back to Disagree – request variance ERO ROP modification		

Organization	Yes or No	Question 5 Comment
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: IRC		
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 has stated.
Response: Q4 kcpl second half 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

Organization	Yes or No	Question 5 Comment
		incorporated into Standard if appropriate.
Response: IRC consistency language **In ERO ROP document**		
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: 13 thanks **14** – will address in response to Attachment A and FRS Form 1 comments		
EKPC	No	The method is not clear in Attachment A.
Response: Attachment A modified		
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: events will be identified quarterly – come back to		
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: L10, as well as ACE, will be affected as FB is modified – **Add comment after fiel trial is developed** – come back to		

Organization	Yes or No	Question 5 Comment
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: ERO will validate and distribute - administrative process covers In the administrative procedure In the adsministrative procedure Same		
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

Organization	Yes or No	Question 5 Comment
		bias are inadequate.
Response: modified req response freom above **Attachment A and FRS Form 1 modified** **Variable Bias – come back to**		
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: administyrative procedure		
NIPSCO	Yes	I guess the ERO will calculate the Bias, interesting.
Response: ero validate and distribute		
Manitoba Hydro	Yes	The implementation schedule seems reasonable.
Response: thanks		
Westar Energy	Yes	
FMPP	Yes	
Progress Energy	Yes	
ENBALA Power Networks	Yes	
NorthWestern Energy	Yes	
Independent Electricity System Operator	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
ISO New Engand Inc.		
Associated Electric Cooperative, Inc.		
Xcel Energy		

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:

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: freq error is within the definition of TLB – may add note that addresses somewhere else		
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: santee cooper – add comment about BARC		
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

Organization	Yes or No	Question 6 Comment
		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: LGE		
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: LGE		
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: could be removed when work done on BARC – plus santee cooper		
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: agree – is in supplemental compliance section – come back to "time"		
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.

Organization	Yes or No	Question 6 Comment
Response: IRC		
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: IRC		
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: agree – add wording from present BAL-003		
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: LGE		
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: done seperately		
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

Organization	Yes or No	Question 6 Comment
		Requirement. See following "Requirements for AGC Operation, January 25, 2011."Requirements for AGC Operation, January 25, 2011Introduction: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 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

Organization	Yes or No	Question 6 Comment
		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 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

Organization	Yes or No	Question 6 Comment
		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 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 use LGE ??? **Comment 17** – recognize from a comp perspective – however have strong concern about operating out of AGC and the effect on primary FR		
EKPC	No	Tie line bias is calculated using (NAI-NSI) while frequency bias is -10B(FA-FS).
Response: santee		
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

Organization	Yes or No	Question 6 Comment
		operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.”
Response: agree and will do		
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: taken to considiration with development of measure **Santee** - LGE		
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: southern co		
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: don b to provide		
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.

Organization	Yes or No	Question 6 Comment
Response: santee - LGE		
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?
Response: don b		
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	

Organization	Yes or No	Question 6 Comment
Progress Energy	Yes	
ENBALA Power Networks	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to our response to Question 17.		
Associated Electric Cooperative, Inc.		
Xcel Energy		

7. Do you agree with the proposed Implementation Plan for this standard? If not, please explain in the comment area.

Summary Consideration:

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: It is the SDT’s belief that the affect reducing the minimum bias setting will have on frequency will not be observable over a short-time interval, hence the annual reductions. Regarding Attachment A, we will incorporate your suggested changes for clarity.		
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
Response: Refer to prior response.		
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

Organization	Yes or No	Question 7 Comment
		should be changed to percent of its estimated maximum generation level in the coming year/0.1 Hz change.
Response: Refer to prior response.		
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 will change the wording in BAL-003 Requirement 5 to read "BAL-003-0.1b Requirement 5 should be phased out by reducing the minimum frequency bias setting per the table." The change is being accomplished through the field trial, we will make this clear. **SDT – what about changing BAL-003-0?**		
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 plan makes no mention of a field trial. It should.Please change all BAL-003-0 to BAL-003-0.1b.
Response: Refer to prior response.		
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

Organization	Yes or No	Question 7 Comment
Response: Refer to prior response.		
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: **SDT – well, how are we going to do this, i.e., what determines success or failure, what is the analytical method that will used to make our determination, where will the results be posted, and how often will they be posted?**		
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. 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: **SDT – what about the possible compliance conflicts, retiring BAL-003-0, and incorporation of R5 into BAL-003-1?**		
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

Organization	Yes or No	Question 7 Comment
		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 believes that it is necessary to observe each step-down increment of the present standard through all four seasons to assure reliability is not adversely impacted. The SDT will coordinate the phase-out steps and tie them to the date the standard is expected to become effective.		
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: Refer to prior response. :		
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.
Response: The SDT will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective.		
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.

Organization	Yes or No	Question 7 Comment
		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 a graduated loosening of the present standard is a more prudent way to proceed. We 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 will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective.		
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 parameters such as Minimum Frequency Response. Alternative methods that measure reliability more frequently could me implemented with a shorter implementation plan.
Response: The SDT will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective. A shorter, alternative plan does not seem prudent.		
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: Refer to prior response.		
EKPC	No	Specific dates should be tied to regulatory approval.
Response: The SDT will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective.		

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 believes the 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: **SDT – AEP's concern is similar to that stated by BPA. So, what about the possible compliance conflicts, retiring BAL-003-0, and incorporation of R5 into BAL-003-1?**		
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 the next level (agree?).
Response: The gradual reduction will be observed throughout the course of each year. It is very unlikely we will encounter a significant issue that will delay implementation, however, should one occur we will have ample time to make course adjustments. **SDT – so, what determines success or failure, what is the analytical method that will used to make our determination, and how will we make course adjustments – if it becomes necessary?**		
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 the staggered implementation will lead to uncoordinated and unreliable operation within an interconnection because these		

Organization	Yes or No	Question 7 Comment
changes have to do with secondary control.		
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 will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective.		
Southern Company	Yes	We did not want to vote on Question 7, but clicked 'yes' in error.
Response: **The SDT thanks you for this revelation and says "good job!"**		
Westar Energy	Yes	Yes, if field testing validates the standard.
Response: Thank you for your comment.		
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

Organization	Yes or No	Question 7 Comment
		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 will coordinate the phase-out/phase-in steps and tie them to the date the standard is expected to become effective. Regarding Attachment A, we will incorporate your suggested changes for clarity.		
Arizona Public Service Company		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?
Response: **SDT – this is a really salient set of questions. How will our analysis deal with the complications of RBC?**		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		
FMPP		
Hydro-Quebec TransEnergie		
Alberta Electric System Operator		
Xcel Energy		

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:

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 FRRSDT agrees with your clarification that the 1% minimum applies to the frequency bias setting and will refine the language accordingly. We also agree to evaluate the need to be somewhat (as opposed to extremely) overbiased. For example, if a Balancing Authority's observed frequency response was .4% of its annual forecasted peak load, and if .4% was above a minimum acceptable frequency bias setting, then a value such as .1% would be added to the observed computed frequency response for the setting to make it less likely for frequency response to 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 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

Organization	Yes or No	Question 8 Comment
		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 FRRSDT agrees with your clarification that the 1% minimum applies to the frequency bias setting and will refine the language accordingly. We also agree to evaluate the need to be somewhat (as opposed to extremely) overbiased. For example, if a Balancing Authority's observed frequency response was .4% of its annual forecasted peak load, and if .4% was above a minimum acceptable frequency bias setting, then a value such as .1% would be added to the observed computed frequency response for the setting to make it less likely for frequency response to 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 FRRSDT agrees with your clarification that the 1% minimum applies to the frequency bias setting and will refine the language accordingly. We also agree to evaluate the need to be somewhat (as opposed to extremely) overbiased. For example, if a Balancing Authority's observed frequency response was .4% of its annual forecasted peak load, and if .4% was above a minimum acceptable frequency bias setting, then a value such as .1% would be added to the observed computed frequency response for the setting to make it less likely for frequency response to 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 FRRSDT agrees to provide further detail in the next draft.		
IRC Standards Review Committee	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

Organization	Yes or No	Question 8 Comment
		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 4 year phaseout schedule is…….. The intent is to evaluate changes before further ratcheting down the minimum frequency bias setting to be used in AGC. The intent is to have a frequency response obligation (FRO) that represents the minimum requirement for reliable interconnected operations which will be measured for compliance, and also a frequency bias setting which can differ from the FRO value and whose compliance will only evaluate whether it was implemented and used properly 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: See previous response.		
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 FRRSDT 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%

Organization	Yes or No	Question 8 Comment
		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 your comment seems to be a misstatement. The FRRSDT consensus is 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.		
Westar Energy	No	The 1% requirement should be phased out with the implementation of this standard.
Response: The intent of the field trial is to find a better minimum value for frequency bias settings.		
FMPP	No	There still needs to a floor value; 1% may not be the correct value, but zero is not the correct floor.
Response: The intent of the field trial is to find a better minimum value for frequency bias settings.		
American Electric Power	No	Please see response to question 7.
Response:		
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

Organization	Yes or No	Question 8 Comment
		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 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

Organization	Yes or No	Question 8 Comment
		believe the result should be a significant increase in secondary control costs to meet the CPS1, CPS2, or draft BAAL requirements.
Response: The FRRSDT appreciates sharing your analyses of the impact on secondary control. Please share the technical data to the extent possible with the FRRSDT. The FRRSDT will perform comparable analyses during the field trial to seek the proper balance of the benefits of having less overcontrol that is perceived to be occurring now, versus the possibility of increasing secondary control due to smaller frequency bias settings.		
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 proper control, and can be different than the frequency bias obligation. The FRRSDT will try to better clarify how the frequency response obligation will be determined.		
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.
Response: The FRRSDT will be re-evaluating and clarifying the phase-out plan.		
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 phase-out plan is designed to find the best floor to use with 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 FRRSDT is attempting to validate its choice of a metric for measuring natural frequency response.		
Progress Energy	Yes	We have seen actual system operations harmed by the current, excessive biasing requirement on several occasions.
Response: Thank you for your input.		

Organization	Yes or No	Question 8 Comment
NIPSCO	Yes	Obviously it will bring it closer. The 4 year phase-in is a great idea.
Response: Thank you for your input.		
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: Thank you for your input.		
Patterson Consulting, Inc.	Yes	Moving Frequency Bias Settings closer to natural Frequency Response is critical to improving observation, reporting, and control.
Response: Thank you for your input.		
South Carolina Electric and Gas	Yes	
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	

Organization	Yes or No	Question 8 Comment
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: Thank you for your input.		
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: Thank you for your input.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		
Hydro-Quebec TransEnergie		
Xcel Energy		

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:

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: we agree & document is in place		
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:		
MRO's NERC Standards Review Subcommittee	Yes	The field test is not identified in the implementation plan. It should be.
Response:		
Midwest ISO Standards Collaborators	Yes	The field test is not identified in the implementation plan. It should be.
Response:		

Organization	Yes or No	Question 9 Comment
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:		
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.
Response:		
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: IRC		
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: IRC		
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:		
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 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.

Organization	Yes or No	Question 9 Comment
Response:		
NIPSCO	Yes	Great idea
Response:		
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:		
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:		
American Electric Power	Yes	The changes proposed should be thoroughly tested before any implementation.
Response:		
Patterson Consulting, Inc.	Yes	A field test will provide valuable refinment and verification of parameters, and should identify unexpected ramifications.
Response:		
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:		
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:		

Organization	Yes or No	Question 9 Comment
Santee Cooper	Yes	
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:		

Organization	Yes or No	Question 9 Comment
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
Associated Electric Cooperative, Inc.		
Xcel Energy		

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:

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).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 of the words “largely stabilized” would allow the following exemplary event to be selected. The frequency drops from 60 Hz to 59.94 Hz in 6 seconds, and then the rate of change lessens as the frequency drifts slowly to 59.935 Hz at 20 seconds. With respect to point A, the intent was to use all samples available in that specified time window based on the EMS scan rate of the Balancing Authority. The thresholds will be determined by subject matter experts who have a familiarity with actual historical events. There is no intent to seek per event compliance, as data quality issues make that type of analysis difficult to justify. Experimentation with prospective metrics has shown that median and mean values will converge to a stable value with 20 samples spaced throughout the year. The intent is to include both on and off peak values as they occur naturally and meet the criteria specified. The FRRSDT is considering the posting of events on a quarterly basis (e.g.) to support Balancing Authorities that wish to perform analyses during the course of the year.		
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 FRRSDT will work with WECC subject matter experts to refine the selection criteria for that interconnection.		

Organization	Yes or No	Question 10 Comment
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 FRRSDT is developing the next version of Form 1, and it will clarify the mechanics of how a Balancing Authority excludes an event (the ERO will not exclude events). The Balancing Authority would not be required to replace one event with another that it chooses. Our studies have shown that the mean and median will converge successfully to a valid result with 20 samples, and the median is more resistant to single event contamination than the mean. The typo noted will be fixed.		
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, but the intent is to choose 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, but the intent is to choose 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 events to get a sufficient sample set size. The FRRSDT is open to suggestions to refine the selection criteria for each interconnection. A balance needs to be struck between having too few samples that result in less computational accuracy, versus having samples		

Organization	Yes or No	Question 10 Comment
that are not very representative of actual response that would occur for the larger 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. 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: One intention of the selection criteria is to select events such that point C is clearly away from the typical generator governor deadbands in the interconnection. While there is geographic diversity among point C (and other) frequency values, the variation is not that large for most events and most Balancing Authorities. Balancing Authorities will be using their local frequency measurements in each sample for points A and B based on their EMS data. While the FRRSDT hopes to choose events such that per Balancing Authority exclusions based on local frequency values will not be necessary, it will consider high local frequency as a possible exclusionary criterion in the next version of Form 1. The noted typo will be fixed.		
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 intention here was to typically exclude such events. However, some may be interesting and valuable events to include, and that wording would give the subject matter experts selecting the events the leeway to include such events. The FRRSDT will consider a change to “shall” language, and take away such flexibility from the subject matter experts.		
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: The event size will be specified on an interconnection basis in consultation with subject matter experts within that interconnection. The events will be chosen by subject matter experts for the particular interconnection.		

Organization	Yes or No	Question 10 Comment
Beacon Power Corporation		
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 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, the FRRSDT intends to issue its event selection quarterly to lessen the lag for those Balancing Authorities who wish to perform their own intra-year analyses. Generally, 25 events are available in each calendar year, but the use of a few events from the preceding year is not expected to contaminate the results significantly. The FRRSDT is re-evaluating its exclusionary criteria and is also developing a process to permit reasonable adjustments for individual events.		
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, 25 events are available in each calendar year, but the use of a few events from the preceding year is not expected to contaminate the results significantly. The FRRSDT's intention is that the subject matter experts will choose events during which rapid load changes and large schedule changes are unlikely. Large schedule changes are found typically at 7 and 8 AM, and at 10 and 11 PM, and they usually occur +/- 5 minutes from the top of the hour. Your suggestion about having BAs exclude those events could be problematic due to the vastly different sizes of Balancing Authorities. The FRRSDT is developing		

Organization	Yes or No	Question 10 Comment
manual correction capability for the sampling process, and that combined with the use of a median value should lessen the impact of such skewing tendencies.		
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, but it is beyond the present scope of the FRRSDT.		
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 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

Organization	Yes or No	Question 10 Comment
		process to be used, but not a binding one. In short, the purpose and intention of Attachment A is not communicated unambiguously.
Response: The flexibility in item 3 was intended to give the subject matter experts guidance in choosing the best possible events, as in some years the resultant events may not meet the all of the ideal criteria. The FRRSDT will improve the clarity and review the issue of whether the selection criteria should be hard or soft requirements.		
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 these 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 FRRSDT will review your concern and determine how best to set selection criteria for WECC. There will be a capability for excluding an ERO specified event based on data quality problems in the next version of Form 1. There will be a capability for making manual adjustments to the actual net interchange values for schedule ramping in the next version of Form 1. The flexibility in the selection criteria will allow the subject matter experts to avoid likely periods of rapid load change (e.g., morning pickup and declining late evening load) and +/-5 minutes about the top of the hour to the extent possible. The intention was to guide the subject matter experts in choosing the "least evil" data set so that relatively few adjustments 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 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 magnitude of the frequency change and the initial frequency values were selected such that most generators on the interconnection should be		

Organization	Yes or No	Question 10 Comment
out of their deadband values. There is no intent to seek per event compliance, as data quality issues make that type of analysis difficult to justify. Our studies have shown that the mean and median will converge successfully to a valid result with 20 samples, and the median is more resistant to single event contamination than the mean. Generally, the subject matter experts will use high speed frequency recorders to select their events, and technology that has become available recently allows for cross-checking 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 magnitude of the frequency change and the initial frequency values were selected such that most generators on the interconnection should be out of their deadband values. There is no intent to seek per event compliance, as data quality issues make that type of analysis difficult to justify. Our studies have shown that the mean and median will converge successfully to a valid result with 20 samples, and the median is more resistant to single event contamination than the mean.		
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).
Response: The magnitude of the frequency change and the initial frequency values were selected such that most generators on the interconnection should be out of their deadband values. There is no intent to seek per event compliance, as data quality issues make that type of analysis difficult to justify. Our studies have shown that the mean and median will converge successfully to a valid result with 20 samples, and the median is more resistant to single event contamination than the mean.		
Arizona Public Service Company	Yes	AZPS would recommend using a lesser number of events and more severe events in the calculation.
Response: A balance needs to be struck between having too few samples that result in less computational accuracy, versus having samples that are not very representative of actual response that would occur for the larger events of concern.		
NIPSCO	Yes	Pretty good

Organization	Yes or No	Question 10 Comment
Response: A balance needs to be struck between having too few samples that result in less computational accuracy, versus having samples that are not very representative of actual response that would occur for the larger events of concern.		
EKPC	Yes	Please provide detailed information on the 25 events that will be chosen for the event.
Response: Our studies have shown that the mean and median will converge successfully to a valid result with 20 samples, and the median is more resistant to single event contamination than the mean.		
Manitoba Hydro	Yes	Yes, 25 events should be sufficient to determine the FRM, while not overburdening the resources performing the analysis.
Response: Thank you for your 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

Organization	Yes or No	Question 10 Comment
		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 for almost all Balancing Authorities. It is intended that the events will be selected for the Balancing Authorities, and the Balancing Authority may exclude some events for certain conditions such as a data quality problem.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to the SDT response to Question 17.		
ISO New Engand Inc.		
Associated Electric Cooperative, Inc.		
Independent Electricity System Operator		

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:

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 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: FRS Form 1 revisions address this issue **There is presently no obligation for generator only** **This is a methodology that is technologically neutral and provides an allocation across 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

Organization	Yes or No	Question 11 Comment
		(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: mro		
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: 1st part of mro		
FirstEnergy	No	We believe that more work is needed on this document and the requirements to provide for more clarity.
Response: 1st part of mro		
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.

Organization	Yes or No	Question 11 Comment
		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 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: first energy & attachment part of standard RAS events excluded from analysis (put into attachment a) Para 1 has been addressed Was set as a minimum for selection of events 8 sec - In process of analysis -16 – due to varying agc scan rates to obtain an average “third para” – “second to last” – no req in place today – the ba that is providing FR recog import and will continue – those not providing adequate and sustained FR will be identified through the measure FBS floor - We disagree with comment – we are not setting a floor “FRO” - This is defined		
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: wew recog this and havew responded with aqn enhanceds FRS form 1 and broken Att A into two doc'sa to better explain		
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: SPP		
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: SPP		
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: Att A response **If att referenced in req becomes enforceable**		

Organization	Yes or No	Question 11 Comment
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: administrative proc provides clarity **If not meet then non compliant - The standard is setting a minimum FR not prescribing a method to meet the req** -		
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: based on empirical studies performed by the sdt demonstrates that median is more resilient to data quality problems extreme values in observations		
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 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

Organization	Yes or No	Question 11 Comment
		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 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

Organization	Yes or No	Question 11 Comment
		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 – revised att provides clarity **Comment 21 – use "data archive"** **Com 22 – agree – will put averaging periods based on agc scan rate (reference table)** **Com 23 – admin process will look at NERCs results HILF study** **Com 24 – BPA response for allocation** **Com 25 – Come back to after HI comments on Q 16 & 17** **Com 26 & 27 & 28 – thanks for your observations – the sdt has taken your comments under consideration in its development process**		
FMPP	No	It is useful, but Attachment A is not clear.
Response: rev att a 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: this std is expected to replace all versions of BAL-003 presently in effect **Revised frs form 1 should clrify**		
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

Organization	Yes or No	Question 11 Comment
		Setting?
Response: aep response **Bpa response** ?? on responsibility for FBS		
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: howard I response on revise att a		
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: thank you & **Revised att a**		
NIPSCO	Yes	Not sure if all the requirements need to be explained, we'll wait for future postings.
Response: thank you & revised att a		
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: att a revised **HI response agc support & will provide in att a**		
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: provided in att a		

Organization	Yes or No	Question 11 Comment
Seattle City Light	Yes	
EKPC	Yes	
ENBALA Power Networks	Yes	
SERC OC Standards Review Group	Yes	
Kansas City Power & Light	Yes	
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: att a revised and provided examples for clarity **Fro is obligation - frm is measure**		
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: background doc revised – come back to after revisions		
ISO New Engand Inc.		Attachment A is useful, but it does not provide a clear understanding of all topics and issues.
Response: att a revised and provided addtl clarity		

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response:		
Associated Electric Cooperative, Inc.		
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
Xcel Energy		

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:

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:		
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:		
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:		
ERCOT	No	It is one method, but not necessarily the only proper method. Not all existing methods need to be replaced.

Organization	Yes or No	Question 12 Comment
		The SRC suggests scan data could be used so that different metrics can be evaluated.
Response:		
ISO New Engand Inc.	No	It is one method, but not necessarily the only proper method.
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.
Response:		
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:		
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

Organization	Yes or No	Question 12 Comment
		operational issues, such as lower L10 values and possible CPS2 compliance factors.
Response:		
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.
Response:		
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

Organization	Yes or No	Question 12 Comment
		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:		
Duke Energy	No	Other factors need to be considered and incorporated in the calculation. See comments to 1 and 2 above.
Response:		
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:		
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:		
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.

Organization	Yes or No	Question 12 Comment
Response:		
LG&E and KU Energy	Yes	The form must have clear instructions on its use and meanings of the terms.
Response:		
FirstEnergy	Yes	Although the method seems acceptable in theory, the results of the field test will be needed to validate the methodology.
Response:		
SERC OC Standards Review Group	Yes	The form must have clear instructions on its use and meanings of the terms.
Response:		
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:		
NIPSCO	Yes	Seems straightforward compared to other methods
Response:		
EKPC	Yes	The form should include clear instructions for use and clear definitions for terms.
Response:		
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:		

Organization	Yes or No	Question 12 Comment
Seattle City Light	Yes	
We Energies	Yes	
Westar Energy	Yes	
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:		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response:		
Hydro-Quebec TransEnergie		

Organization	Yes or No	Question 12 Comment
Beacon Power Corporation		
Southern Company		
Associated Electric Cooperative, Inc.		
Xcel Energy		

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:

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: Thank you for your comment. 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 a additional measure, this could be used in the field trial to determine the magnitude of the measurement error of Form 1. 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: 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		

Organization	Yes or No	Question 13 Comment
their data. Adjustments should be made in the columns provided in the revised 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: 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: 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: Form 1 has been revised to account for known variables that will impact the measure. The SDT believes that when actual Primary Frequency Control improves within a BA, 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.		

Organization	Yes or No	Question 13 Comment
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: Thank you for your response. The SDT agrees.		
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 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 BA's bias setting closely matches natural Primary Frequency Control, L10's and CPS2 and CPS1 will more accurately measure the BA's ACE impact on the Interconnection's frequency. This may result in more difficulty in being compliant to CPS1 and CPS2. The sample size of identified events is intended to address the variability of performance of a BA. 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

Organization	Yes or No	Question 13 Comment
		estimate of the true value of Frequency Response.
Response: Response 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 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: Form 1 has been revised to account for known variables that will impact the measure. The SDT believes that when actual Primary Frequency Control improves within a BA, 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: Form 1 has been revised to account for identified variables in measuring Primary Frequency Control. The SDT agrees that generator governor response, Primary Frequency Control, would be a beneficial measure to determine proper delivery of frequency response. The SDT also agrees that generator governor and droop settings will impact Primary Frequency Control but this is outside the scope of this project and a separate SAR will be required to address governor settings. The SDT is not aware of a WECC study 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 for 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 headroom, elements of the transmission system can become overloaded during contingencies.		

Organization	Yes or No	Question 13 Comment
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 measure. 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: Form 1 has been revised to account for know 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 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: Thank you for your comment. 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 definitions and instructions.		
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 definitions.		
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 definitions and instructions.		
Midwest ISO Standards	Yes	We agree that using Points A and B is correct and the calculations in the spreadsheet are correct.

Organization	Yes or No	Question 13 Comment
Collaborators		
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 identify problems with 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 definitions and instructions.		
EKPC	Yes	The form should include clear instructions for use and clear definitions for terms.
Response: The SDT agrees and has revised Form 1 with definitions and instructions.		
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.

Organization	Yes or No	Question 13 Comment
Response: The SDT will identify proposed methods of determining the FRO so the proper measure of the FRM can be determined.		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response: Please refer to response for Question 17.		
ISO New Engand Inc.		
Southern Company		
Associated Electric Cooperative, Inc.		
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
Xcel Energy		

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:

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:		
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: mro		
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: mro		
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: mro		
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:		
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:		
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:		
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:		
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:		
IRC Standards Review Committee	No	The document explains much of the FRS Form 1, but not all, as commented previously.

Organization	Yes or No	Question 14 Comment
Response:		
ERCOT	No	The document explains much of the FRS Form 1, but not all, as commented previously.
Response:		
Progress Energy	No	The forms clarity can only truly be found by reverse engineering the formulas within each of the cells.
Response:		
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:		
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 Supplemental Frequency Responses that can be applied under restricted conditions to supplement it.Section

Organization	Yes or No	Question 14 Comment
		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:

Organization	Yes or No	Question 14 Comment
		Comment 48: In the first sentence, the phrase “as allowed by the Frequency Bias Settings” refers to the 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:		
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:		
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:		
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.
Response:		
Santee Cooper	Yes	The instructions should include how to take into account changes in metered non-conforming loads.

Organization	Yes or No	Question 14 Comment
Response:		
NIPSCO	Yes	We didn't read it but the form looks good.
Response:		
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:		
FMPP	Yes	
Seattle City Light	Yes	
Manitoba Hydro	Yes	
NorthWestern Energy	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response:		
Southern Company		

Organization	Yes or No	Question 14 Comment
ISO New Engand Inc.		
Hydro-Quebec TransEnergie		
Beacon Power Corporation		
Westar Energy		
Associated Electric Cooperative, Inc.		
Alberta Electric System Operator		
Xcel Energy		

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:

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 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 by the FRRSDT. How should the FRRSDT respond?		
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: Does BAAL address this?		
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.

Organization	Yes or No	Question 15 Comment
Response: Since these are new Requirements, the current RSG agreements probably do not address Frequency Response. The FRRSDT is just offering this as a suggestion that needs to be vented.		
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 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, but automatic deployment of other devices could be used to provide frequency response. Underfrequency relays tripping load would happen during significant frequency excursions.		
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.

Organization	Yes or No	Question 15 Comment
Response: Same as above to the IRC Standards Review Committee		
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: Comments noted.		
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: It is correct schedules are too slow. Need an answer for GO vs. BA accountability.		
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 ResponseOr 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.
Response: The NERC Standards and Requirements are not meant to dictate how the Requirements are met, such as a market. A market can be created by a region, sub-region, ISO, RTO or other entities to facilitate meeting the NERC Reliability Requirements, but the NERC Reliability Requirements do not create a market.		
NIPSCO		We reviewed the related NERC Training Document from 2003 and your proposed method seems like the best

Organization	Yes or No	Question 15 Comment
		approach.
Response: Thanks 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: Frequency Bias does not affect frequency response.		
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.

Organization	Yes or No	Question 15 Comment
Response: Comments 50 & 51 - The NERC Standards and Requirements are not meant to dictate how the Requirements are met, such as a market. A market can be created by a region, sub-region, ISO, RTO or other entities to facilitate meeting the NERC Reliability Requirements, but the NERC Reliability Requirements do not create a market. Comment 52 – Comments noted.		
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 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

Organization	Yes or No	Question 15 Comment
		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 that is required in the Standard meets the reliability needs of the interconnections. Since these are new Requirements, the current RSG agreements probably do not address Frequency Response. The FRRSDT is just offering this as a suggestion that needs to be vented.		
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 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: It is not a requirement for a customer to be a frequency responsive load, but it is an option.		
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: This issue has been discussed by the FRRSDT. How should the FRRSDT respond?		
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: This issue has been discussed by the FRRSDT. How should the FRRSDT respond?		
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

Organization	Yes or No	Question 15 Comment
		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.
Response: The NERC Standards and Requirements are not meant to dictate how the Requirements are met, such as a market. A market can be created by a region, sub-region, ISO, RTO or other entities to facilitate meeting the NERC Reliability Requirements, but the NERC Reliability Requirements do not create a market.		
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: Since these are new Requirements, the current RSG agreements probably do not address Frequency Response. The FRRSDT is just offering this as a suggestion that needs to be vented.		
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 NERC Standards and Requirements are not meant to dictate how the Requirements are met.		
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.		

Organization	Yes or No	Question 15 Comment
South Carolina Electric and Gas		
Associated Electric Cooperative, Inc.		
Arizona Public Service Company		
We Energies		
American Electric Power		
Southern Company		
FMPP		
EKPC		
Seattle City Light		
Manitoba Hydro		
Hydro-Quebec TransEnergie		
SERC OC Standards Review Group		
MRO's NERC Standards Review Subcommittee		
LG&E and KU Energy		
Midwest ISO Standards Collaborators		

Organization	Yes or No	Question 15 Comment
Xcel Energy		

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:

Organization	Yes or No	Question 16 Comment
FirstEnergy		We are not aware of any conflicts at this time.
Response: thanks		
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. 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.

Organization	Yes or No	Question 16 Comment
		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: disagree **Bring order 693 and march 18 wording plus later order**		
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 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.

Organization	Yes or No	Question 16 Comment
Response: irc response		
Arizona Public Service Company		AZPS would like clarity if Interpretations of BAL-003-0 will be part of BAL-003-1.
Response: the standard replaces all existing BAL-003's and incorporates interpretations		
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 the creation of the most efficient markets in this Ancillary Service.
Response: sdt acknowledges your concerns but is outside the scope of the 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: we agree that the standard should not place an entity in double jeopardy – each yrs events will be unique for the evaluation period		
American Electric Power		This Standard has the potential to affect Standards involving CPS performance with respect to the calculated CPS Bounds L10 if relative.

Organization	Yes or No	Question 16 Comment
Response: we agree that this std affects the FBS to other stds that use this as a component, such as cps dcs **Referencing the reduction of the 1% minimum to natural FR**		
Northeast Power Coordinating Council		Refer to the response to Question 17.
Response:		
Patterson Consulting, Inc.		None.
Kansas City Power & Light		No other comments.
Duke Energy		
We Energies		
SERC OC Standards Review Group		
Southern Company		
Progress Energy		
Hydro-Quebec TransEnergie		
EKPC		
ISO New Engand Inc.		
Seattle City Light		
Manitoba Hydro		

Organization	Yes or No	Question 16 Comment
Beacon Power Corporation		
Westar Energy		
ENBALA Power Networks		
NIPSCO		
NorthWestern Energy		
Bonneville Power Administration		
SPP Standards Development		
Santee Cooper		
MRO's NERC Standards Review Subcommittee		
LG&E and KU Energy		
Midwest ISO Standards Collaborators		
South Carolina Electric and Gas		
Associated Electric Cooperative, Inc.		
Alberta Electric System Operator		
Independent Electricity System Operator		

Organization	Yes or No	Question 16 Comment
Xcel Energy		

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:

Organization	Yes or No	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 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

Organization	Yes or No	Question 17 Comment
		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 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

Organization	Yes or No	Question 17 Comment
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. **Gen std outside scope** **N-2 still being evaluated**		
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 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

Organization	Yes or No	Question 17 Comment
		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 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: npcc response .4% evaluating		
Santee Cooper		Again, we believe that the SDT should consided or prior years' data. We are concerned with how the total

Organization	Yes or No	Question 17 Comment
		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: come back to		
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: dwr develop		
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.
Response: mro		
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

Organization	Yes or No	Question 17 Comment
		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: attachment a revised **Standard provides metrics in which markets and independent solutions can be developed** RC's can provide further restrictions Methodology tested during 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 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: att a revision **Based on forecasted** **Field trial for methodology** **Examples of how allocated for clarity**		
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

Organization	Yes or No	Question 17 Comment
		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: serc		
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: sdt conducting webinar on ?????		
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: R1 – standard req is for response not reporting (one answer for all) R2 – same as r1 – reporting handled in comp section		
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: corrected		

Organization	Yes or No	Question 17 Comment
Modified R4 (see STD 2011 04 05) Automatically being done in the calculation form		
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 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

Organization	Yes or No	Question 17 Comment
		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: bpa response **Modify supplemental 1st para to include RSG (**some type of joint) **Modify supplemental r2 to include rsg (some type of joint)** **Use statement from q1 – q5** **Att a revised** Bal-005 already cites the data req for archiving ERO will review – "indication or evidence of a secondary event" (criteria) Native load is a defined term in the NERC Glossary		
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 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

Organization	Yes or No	Question 17 Comment
		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: irc response		
Progress Energy		We believe this standard insufficiently addresses the true nature of the problem; however it does accuratly address the fact 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: we agree that generator level can solve but this std is looking at the resource level as directed in O 693		
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: rsg is one way of complying – (compliance check)		
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

Organization	Yes or No	Question 17 Comment
		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 with respect to reliability and economics. Comment 55: 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 – come back to (study in field trial) **Comment 55** – considered in the development		
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

Organization	Yes or No	Question 17 Comment
		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: this std is addressing a more conservative point b result to protect for point c ufls **We encourage real**-time monitoring of FR as a good practice but this is beyond scope (being addressed by BARC)		
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 att a includes fro determination Bill and I Yes – this can change during the year – utilities have the ability to modify		
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: FRS form 1 revised		
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

Organization	Yes or No	Question 17 Comment
		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 std is not designed to be a emergency ops standard – however this standard could assist an entity in identifying and solving the problem you have mentioned. **The paper is not a product of this SDT** – it is a information paper requested by the NERC OC – the RS received industry comment that was 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 FBS is close to natural FR the agc impacts would be minimal or none **Compliance wording from above**		
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,

Organization	Yes or No	Question 17 Comment
		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: 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: BARC work out of scope – will pass on to SC

Compliance from above

Field test – come back to & will have a document explaining

Organization	Yes or No	Question 17 Comment
Standard will provide the metrics and the market will define itself – the SDT encourages you to work with NAESB to define a market. We welcome your comments – work with NAESB (from above) - We disagree – the SDT does not believe that the IA should be a approving body for a standard Compliance response from above – we agree that it would be interchange We have incorporated an improved frs form 1 with instructions for its use – the sdt thanks you for your response – however based on the information provided the sdt is unsure of your question and can not provide a response more than provided 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..."
Response: revised R4		
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

Organization	Yes or No	Question 17 Comment
		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 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: 1) Z& 2) – thanks

3) – the compliance response from above

4) left out for 1st draft (would have to revise) and needed input from field trial

Organization	Yes or No	Question 17 Comment
1) sefrd response from above 2) frm response from earlier 3) & 4) eaqrlier response a) compliance response (irc) b) req is results and supplemental is reporting (from earlier) – earlier response concerning timing of reporeting c) revised standard changes methodology from subjective to directed 2 a) same as b) above 2 b) disagree – if fixed then report annual – if changes within the year by exception variable bias is reported in a monthly average form 3) point c is not needed for the methodology being recommended – dictating a & b – revised standard and administrative process will provide clarification		
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: paper written response from earlier – some of the sdt membership makeup as represented is from the NERC RS **Refer to SRC comments**		
Kansas City Power & Light		No other comments.
Arizona Public Service Company		
Seattle City Light		
Manitoba Hydro		
Beacon Power Corporation		
NorthWestern Energy		
ENBALA Power Networks		

Organization	Yes or No	Question 17 Comment
FMPP		
Southern Company		
Independent Electricity System Operator		
Midwest ISO Standards Collaborators		

END OF REPORT